

JOINT STAFF WORKSHOP  
CALIFORNIA ENERGY COMMISSION  
CALIFORNIA PUBLIC UTILITIES COMMISSION

In the Matter of: ) CEC Docket No.  
 ) 04-DIST-GEN-1  
COST AND BENEFIT METHODS FOR ) 03-IEP-01  
DEPLOYMENT OF DISTRIBUTED )  
GENERATION ) CPUC Docket No.  
 ) R.04-03-017

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## P R O C E E D I N G S

1:06 p.m.

PRESIDING MEMBER GEESMAN: I'd like to welcome everyone to this Joint PUC and Energy Commission Staff workshop on cost and benefit methods for the deployment of distributed generation.

I'm John Geesman, the Presiding Member of the Energy Commission's Integrated Energy Policy Report Committee. Sitting to my left is Commissioner Jim Boyd, who is the Associate Member of that Committee and the Presiding Member of our 2003 Integrated Energy Policy Report.

That report, as many of you know, placed a primary emphasis on expanding the state's policy attention to distributed generation. And we have worked collaboratively with the PUC in the development of their OIR, or I guess they call it OII, into distributed generation policy matters.

This workshop is primarily aimed at identifying costs and benefits to the utility system of distributed generation technologies. We're going to cover past methods of evaluating that, as well as existing research underway at the Energy Commission.

1           The Energy Commission historically has  
2       placed a very substantial amount of our PIER R&D  
3       money into better integrating distributed  
4       generation into the electric grid. And one of the  
5       primary benefits to us, as an agency, of this  
6       collaboration with the Public Utilities Commission  
7       will be better targeting that R&D program.

8           We hope to learn a lot today. It's the  
9       first in what I'm sure will be a number of  
10      workshops in this area, and I certainly appreciate  
11      all of you coming today.

12           Commissioner Boyd.

13           COMMISSIONER BOYD: Thank you,  
14      Commissioner Geesman. Just a couple of words to  
15      add onto your very thorough and appropriate  
16      introduction. I'm personally very pleased that  
17      this event is taking place. I salute the  
18      cooperation between the agencies and the staff, in  
19      particular, and their reaching out to the  
20      stakeholders that is taking place, as evidenced by  
21      this workshop and by your reference to future work  
22      with folks.

23           As one who sat painfully close to the  
24      electricity crisis all through its days, DG, self-  
25      gen, call it what you want, became very near and

1        dear to my heart, as something obviously that, in  
2        my opinion, this state needed more of, and needed  
3        to facilitate. And I'm glad to see that this  
4        effort is underway.

5                There are too many reasons, to take your  
6        time to state, as to why this is a good thing.  
7        And there are too many reasons to state that you  
8        all know as to why this is now a very difficult  
9        thing to do in this state.

10               But as we have righted the ship, or  
11        refloated the ship and are moving away from the  
12        eye of the storm, or out of the storm completely,  
13        let's just say that this is a very important  
14        component of where we need to be some day. So I'm  
15        glad to see this action underway.

16               Thank you.

17               PRESIDING MEMBER GEESMAN: Mark, why  
18        don't we turn it over to you.

19               MR. RAWSON: Great, thank you,  
20        Commissioners.

21               Welcome to the Energy Commission. I'm  
22        glad that we had such a good turnout today. I'd  
23        like to introduce myself, I'm Mark Rawson. I'm  
24        the Staff Lead on the Energy Commission's Order  
25        Instituting Investigation on DG issues.

1           And with me is my colleague, Valerie  
2       Beck from the CPUC, who's the Lead on the CPUC's  
3       OIR. And we were going to walk you through some  
4       opening remarks about what we want to accomplish  
5       today together.

6           Just wanted to say that -- give you a  
7       little rationale behind the workshop. There's  
8       been a lot of work done in the cost/benefits area  
9       with respect to DG. Lots of theoretical work,  
10      most of it qualitative.

11          At the end of the CPUC's proceeding they  
12      need a good evidentiary record with respect to  
13      cost/benefit. And I think to do that we need  
14      quantitative knowledge about the costs and  
15      benefits of distributed generation.

16          So the goal of this workshop today,  
17      prior to public comments being submitted to the  
18      CPUC's OIR, are primarily three things that we  
19      want to accomplish. It's to get people thinking  
20      about cost/benefit issues. It's to get people  
21      using common language or terms with respect to  
22      cost/benefit. And it's finally to let people know  
23      some of the research and analysis that's gone on,  
24      or is going on presently, in this area.

25          I want to give you just a couple

1 logistics for today's discussions. We are using a  
2 court reporter for this workshop. And we will be  
3 posting the transcripts from the workshop. And we  
4 ask that the panelists and anybody that comes up  
5 to ask questions during the question-and-answer  
6 period please use the microphones so that we can  
7 capture your thoughts and the discussion.

8 The other part of that is that we'd like  
9 you to state your name and your affiliation when  
10 you speak. And if you could please either  
11 directly before you speak, or afterwards, leave a  
12 business card with the reporter over there so that  
13 we make sure that we get you captured correctly in  
14 the transcript. That would be greatly  
15 appreciated.

16 There's restrooms directly across the  
17 way here. We will be taking a break about halfway  
18 through. There's also a small deli on the second  
19 floor if anybody needs refreshments or anything.

20 So, with the logistics out of the way,  
21 let's talk a little bit about the agenda for  
22 today. We basically have the day split into two  
23 panel discussions. The first panel is going to be  
24 moderated by Scott Tomashefsky. And we're going  
25 to talk about existing cost/benefit analyses and

1 methodologies. We have a fairly expert set of  
2 people to talk today about analyses that have been  
3 done in the past.

4 And then in the second panel we're going  
5 to talk about some of the research that's going on  
6 in the PIER program here at the Commission that  
7 relates specifically to cost/benefit for  
8 distributed generation.

9 We have a lot of things to cover between  
10 now and 5:30, so we're going to try to move things  
11 along fairly quickly.

12 MS. BECK: First I'd like to add my  
13 thanks to the thanks of the Commissioners and  
14 Mark, thank you all for coming. This is kind of a  
15 kickoff, so to speak, of the Commission's new OIR  
16 which was just opened last month.

17 The purpose of the OIR obviously would  
18 be to encompass all things DG into one rulemaking.  
19 And the primary goal and the first task of this  
20 rulemaking is to develop a cost/benefit  
21 methodology. The Commission has a mandate to do  
22 that, and we're a little behind in that respect,  
23 but, you know, there's been a lot going on. But  
24 it's really critical now to develop the  
25 cost/benefit methodology.

1           One of the reasons it's important to do  
2           it first is because we need it to flow into some  
3           of these other priorities here, particularly how  
4           to scope out DG as a utility procurement resource.

5           The self-incentive program is also  
6           encompassed under the OIR, so we're going to try  
7           to take everything we've learned and apply it  
8           towards this cost/benefit project. And with the  
9           CEC's help, learn a little bit about what their  
10          PIER projects are doing and get some ideas from  
11          the group and from the CEC on how we can integrate  
12          that data and that information into the  
13          Commission's rulemaking.

14          MR. RAWSON: We mentioned earlier that  
15          the Energy Commission opened an Order Instituting  
16          Investigation with respect to DG. And this is our  
17          parallel proceeding to the CPUC's OIR so that we  
18          can work collaboratively with them on primarily  
19          three issues, cost/benefit analysis, revisions,  
20          potential revisions to interconnection rules, and  
21          progress of research on future DER technologies  
22          that we're investigating here within the PIER  
23          program.

24          To the extent that the information from  
25          our OII can benefit the CPUC in their proceeding

1 we're going to attempt to do that. We'll also be  
2 incorporating what we learned through this  
3 investigation into the 2005 energy report.

4 MS. BECK: We've kind of broken the  
5 cost/benefit methodology into three steps. And  
6 the first one is pretty obvious, what factors  
7 should go into determining costs and benefits. We  
8 did a little bit of that in our prior rulemakings;  
9 hope to really wrap that up in this one.

10 And then once we know what the factors  
11 are, figure out how to quantify them and how to  
12 put that together to a workable model. And then  
13 ultimately what the Commission has said we will do  
14 with that is use it to judge when DG would be an  
15 appropriate option for the utilities and how they  
16 can plan for it, plan for DG in their procurement  
17 process.

18 MR. RAWSON: As Commissioner Geesman  
19 mentioned earlier, basically the day is split into  
20 two subjects, past cost/benefit analyses and  
21 existing cost/benefit research that's underway.

22 I guess the important point here is that  
23 we want participants from today's workshop to  
24 submit any comments they may have with respect to  
25 the discussion today, with their comments, to the

1 CPUC on the OIR, which are due May 15th. We're  
2 trying to lighten the load for people that want to  
3 submit comments, and we don't want to have you  
4 extra work, so if you can incorporate any of your  
5 thoughts about today into your comments to the  
6 CPUC, we encourage you to do that.

7 We also request, though, that you submit  
8 any comments you have to the docket here at the  
9 Energy Commission for the DG OII so that we can  
10 make sure we capture those in our process.

11 So as we move forward in both the  
12 proceedings here for the CPUC and the Energy  
13 Commission, as well as look at research that we're  
14 performing here in the PIER program, we're trying  
15 to address key questions related to cost/benefit  
16 identification and quantification.

17 And these are some of the questions that  
18 we're interested in. And we provide these  
19 questions -- I'm not going to go through them  
20 verbatim -- we provide these questions for context  
21 for today's workshop. As you hear the panelists  
22 present the work that they've been involved in,  
23 some of the research that they've been involved  
24 in, we'd like the participants of the workshop to  
25 think about, you know, these questions regarding

1 identification and quantification methodology.

2 Because these are the questions that we hope to  
3 arrive at a decision from the CPUC that's going to  
4 be well-informed, and it's going to help address  
5 some of the issues that different key stakeholders  
6 have been asking to be addressed for some time.

7 With that kind of opening set of  
8 remarks, I'd like to jump right into the panel,  
9 because we have a fairly long first panel. Want  
10 to hear what they have to say. We've built in a  
11 fair amount of time for questions and answers, so  
12 why don't we go ahead and call the first panel up  
13 and, Scott, if you could go ahead and get us going  
14 on moderating this first panel, we can get  
15 started.

16 (Pause.)

17 MR. TOMASHEFSKY: I'd like to echo the  
18 welcomes of all who have preceded me here. Glad  
19 to see a lot of people I know, and some people I  
20 don't know, and some people that probably don't  
21 want to say that they actually know who I am.

22 We've got about 20 minutes for each of  
23 our speakers. And what I'd like to do, at least  
24 in terms of making sure the process goes  
25 relatively smoothly, we're going to hold off on

1 Q&A until after everybody's had a chance to make  
2 their say.

3 Just a couple words of caution, at least  
4 in terms of, please, as we've said, the  
5 microphones. You'll need to speak into the  
6 microphones, as well, so the court reporter gets  
7 all the verbiage.

8 Let me go ahead and just give a very  
9 brief introduction for each of our speakers. Our  
10 first one, who is standing to my left, is Joe  
11 Iannucci with Distributed Utility Associates. And  
12 I would characterize him as probably a patriarch  
13 of distributed generation. If you go on Google  
14 you'll find his name comes up 141 times, so that's  
15 always a good indication of importance or whether  
16 your name is attached to various filings.

17 But he's done a lot of work in this  
18 area, and he's going to give us a briefing on  
19 probably more than 100 cost/benefit analyses that  
20 have been done. And he'll kind of focus on some  
21 of the more useful methodologies.

22 Second up is going to be Chris Marnay,  
23 who's with Lawrence Berkeley Labs. He's a Staff  
24 Scientist over there. He's done an awful lot of  
25 work on the issue of microgrids. Glad to have you

1 here.

2 Snuller Price is our third speaker with  
3 Energy and Environmental Economics. He co-heads  
4 their transmission distribution planning business.

5 Fourth will be Carl Silsbee with  
6 Southern California Edison Company who will give  
7 the utility perspective on distributed generation.

8 And last, but not least, will be Kevin  
9 Duggan from Capstone, who is Regulatory  
10 Environmental Affairs Manager, who's going to  
11 speak on behalf of the Clean DG Coalition.

12 And with that I'm going to turn it over  
13 to Joe.

14 MR. IANNUCCI: Thank you, Scott. And  
15 can I be heard in the back, way in the back there?  
16 Okay, good. If I can't, somebody scream somewhere  
17 part-way through the presentation.

18 Thank you very much for the opportunity.  
19 I appreciate any opportunity to talk about  
20 distributed resources, and cost/benefits are  
21 really my favorites. They're tricky; they're  
22 yucky at times; they're complicated; they're  
23 interconnected. But we've got to study them, we  
24 have to understand them.

25 What I'll be doing today is going over a

1 study we did first for NREL, finished about a year  
2 ago, which reviewed the best 124 reports we could  
3 find that address benefits, and focused that down  
4 to the 30 best of those.

5 And then Mark has also asked me to pick  
6 out one of those reports, the one that was the  
7 most complete, seemed to do the best job. And  
8 then bore into that one another level deeper to  
9 show you what you can learn if you do a more  
10 comprehensive job of looking at the benefits.

11 So, this is the first half of my  
12 presentation. This is the 30 best DR benefit  
13 studies.

14 We started with our massive files at  
15 Distributed Utility Associates; tried to recall  
16 many papers we'd heard or read, beg, borrowed --  
17 we didn't steal anything, but we would have done  
18 that, I suppose, if we'd had the opportunity, to  
19 find the best reports that deal explicitly with  
20 the value or benefits of distributed resources.

21 Then we tried to prioritize which of  
22 those reports were the most complete and select  
23 the top studies.

24 So these are the attributes that we  
25 looked at, and I'll emphasize the top one over and

1 over again, quantitative benefits data or  
2 analysis. Just because you can say the word  
3 distribution deferral 27 times, doesn't mean that  
4 you've shown me that you can calculate it. Or  
5 that, in fact, the data exists to calculate that.  
6 I don't mean to just pick on distribution  
7 deferral; it's just a good example.

8 So many of those reports had the word  
9 quantification of benefits in the title when you  
10 read the report, it said, wouldn't it be nice if  
11 we could quantify the benefits. So you have to be  
12 really careful.

13 Comprehensiveness was also an important  
14 factor. Accuracy and completeness were actually  
15 tricky. We didn't want to make judgments as to  
16 whether someone didn't know what they were talking  
17 about. We wanted to judge based on whether they  
18 even tried to do the benefits quantitatively. So  
19 we were a little bit lenient on accuracy and  
20 completeness.

21 Clarity was important. Then we get to  
22 lower importance things like the applicability of  
23 cross-technologies. We didn't want to look at a  
24 benefit that only applied to one obscure  
25 technology. And so on.

1           And all the reports had to be available,  
2           and we gave extra points for recent publication  
3           dates. Although some of the old ones actually  
4           were the most complete and the most helpful.

5           This is one of the things that this  
6           group or this OIR process is going to have to  
7           decide on. Which benefits are even on the table.  
8           Let alone which ones you feel you can quantify.  
9           This is not a prioritized list, but it's a fairly  
10          complete list. And this is the list of benefits  
11          that we used to categorize which benefits were  
12          included or not included.

13          We also subdivided those into utility  
14          perspective benefits, customer perspective  
15          benefits, and then joint benefits. Even the joint  
16          benefits probably have two different facets to  
17          them, like reliability. Reliability critically  
18          important to both customers and utility, but the  
19          utility thinks about system average reliability or  
20          even the feeder average reliability. While the  
21          customer putting in distributed resources cares,  
22          you know what, about their reliability. So, two  
23          different calculations, two different ways of  
24          monetizing that.

25          I don't expect you to read this chart.

1 You can't read it even in the handouts. What it  
2 is is the very very beginning of a list of the 30  
3 reports which shows the title, the authors, the  
4 data sources, the benefits methodologies. But the  
5 only thing I want you to know is this middle  
6 part, which has these strange little objects in  
7 here that look like filing cabinets in this  
8 version, are really the benefits. Every time one  
9 of those little filing cabinets shows up, those  
10 are really check marks in the original file. That  
11 benefit was included and quantified in that study.

12 And this happens to be at the top of the  
13 list is a study that had eight of the benefits  
14 included. Generation, transmission and  
15 distribution deferrals, environmental, energy and  
16 reliability, CHP and oh, my gosh, I've forgotten  
17 what DR is, myself. Okay. Demand reduction,  
18 right, from the customer standpoint. And, in  
19 fact, that's the study I'm going to get into in  
20 some detail in just a moment.

21 Now here's the good news and the bad  
22 news. Now, remember I started with 124 reports;  
23 some of you in the audience wrote these, and  
24 probably wrote the better ones. So you're  
25 probably in this group. And I wrote some of them,

1       myself.

2               This is the number of benefits that were  
3       included for each of the studies. So we have  
4       three of the studies of the top 30 included just  
5       one benefit. And, for instance, five of the  
6       studies included two benefits. And one of the  
7       studies included as many as eight. None of the  
8       studies had nine, ten, 12, and so on.

9               This tells me a few things. First of  
10       all, that some benefits were more popular than  
11       others, or easier to quantify. But more than  
12       that, that we have a very immature business. If  
13       this were a telecommunications business, we were  
14       looking at cellphones and trying to look at  
15       attributes of cellphones or something, what we'd  
16       have is a certain number of features that we would  
17       care about. And just about everybody that did a  
18       market study would have all of those features in  
19       there. You might disagree with their data, you  
20       might disagree with their methodology, but what  
21       you would have in bringing it back to this chart  
22       is 30 studies studying 13 benefits. Do we have 30  
23       studies studying 13 benefits? No. We're way  
24       short of doing a complete job.

25               If you look at which benefits were

1 included the most frequently -- this is another  
2 important chart for this proceeding -- again, we  
3 selected which projects seemed to do the best job,  
4 and it turned out that distribution capacity  
5 deferral was number one, followed very closely by  
6 transmission capacity deferral and energy savings,  
7 then generation capacity deferral. Then we drop  
8 off to reliability enhancement. I Squared R  
9 system losses, demand charge reductions. Then  
10 CHP, and then it dribbles off.

11           Some people actually had other benefits  
12 so the list could have been longer, but this is  
13 the summary of it. And I don't want to make a  
14 judgment call for you today, but if I were  
15 thinking about which benefits I would be including  
16 in this proceeding as it goes further, I'd start  
17 from the top of this list and work down. And  
18 maybe you should look at these top eight, or maybe  
19 you want to truncate it to the top five. But at  
20 least it's a running start as to which benefits  
21 the industry or everyone in this field over the  
22 last ten years think are important.

23           And another part of what we're going to  
24 have to do eventually as a group, probably not  
25 today, is to put these benefits into some kind of

1 a matrix like this, some kind of a quadrants,  
2 where we have two axes. The importance of these  
3 benefits and the tractability of the benefits.

4 So things that are very important are at  
5 the top; things that are very easy to do are at  
6 the right. And the promised land is up in the  
7 upper right-hand quadrant. Hopefully all of the  
8 important benefits are up there and are also  
9 tractable.

10 And I'm going to be more specific. I'm  
11 going to dip down into one level deeper into the  
12 onion. What do I mean by important? Well  
13 defined. That means that two people look at the  
14 same benefit, they can nod their heads and say,  
15 yeah, that's what I mean by that benefit.

16 Number two, it has a high value in  
17 dollars per kilowatt. So, in any installation  
18 where this benefit occurs, it's a high value  
19 compared to one of the very small ones. And for  
20 the purposes of these hearings it should occur in  
21 a large percentage of California systems. Now,  
22 large may only be 7 percent or 10 percent or  
23 something, but at least you should skew it towards  
24 something that happens frequently.

25 Now, tractable. This is really

1       slippery, but I'm going to try. First of all, a  
2       calculation methodology exists. So there is an  
3       equation with an equal sign, and somewhere on the  
4       right side of that are some functions. I'm not  
5       asking that they be fancy; like  $a \times b$  would be  
6       fine with me, okay.

7               The methodology should also not be  
8       controversial, so that everyone agrees that that's  
9       the right way to do it. And there are many ways  
10      to do many of these benefits. I'm not criticizing  
11      anyone, just pointing out the multiplicity of  
12      ways.

13             And then the part that most people  
14      forget entirely, that the data is available to put  
15      in it. If you give me an equation that the  
16      benefit is  $a \times b$ , but you refuse to give me  $a$  or  
17       $b$ , or you give me  $a$  and  $b$ , but won't tell me where  
18      you them from, I think we're going to have a  
19      difficult time in terms of the tractability of  
20      this benefit. So the data should also be  
21      noncontroversial. But my chart probably is.

22             What are the observations? Well, the  
23      obvious one was that there really weren't an awful  
24      lot of quantitative benefits in many of the  
25      studies that we looked at. In terms of

1 methodologies, we did not decide which ones were  
2 good methodologies and which ones were bad. We  
3 were so pleased to see any methodologies at all in  
4 this top 124 studies that we gave them a pass,  
5 even if it looked a little bit questionable.

6           There's also no uniformity. No two  
7 sponsoring organizations in all of those studies  
8 used the same analytical model to calculate the  
9 benefits. Again, evidence that we're right at the  
10 beginning of an industry, not in a mature  
11 industry. And most of the studies just dealt with  
12 one or two.

13           So, obviously being a consultant we made  
14 some recommendations, you know, where should we go  
15 from here. We thought that the most important  
16 thing to do next was to delineate the strengths  
17 and weaknesses of the alternative methodologies.  
18 We didn't have the funding to do that. Ours was  
19 more -- while it was certainly well beyond a  
20 bibliography, I mean it was true analysis of which  
21 were good, bad and ugly of those studies. And  
22 that, in fact, there should be also a benchmark  
23 approach for each benefit.

24           I didn't write these bullets for this  
25 meeting. So you can see why I was asked to talk

1       about this report. It's right exactly to the  
2       point that we are here in this hearing, that we  
3       need to do both of those things. What are the  
4       alternative methodologies. Which ones. What's a  
5       benchmark approach, and by that I mean an equation  
6       with an equal sign, and a source of data that's  
7       non controversial.

8               So let me go on to the study that seemed  
9       to get the highest grades, and it was a tough  
10      choice, but at least it had the most benefits. It  
11      was that study that had eight benefits out of 13,  
12      at least. And it was completed in February 2003  
13      for the Department of Energy. And, yes, we were  
14      involved in doing this study.

15             It was the economic and technical  
16      analysis of a real distributed generation  
17      opportunity in a real place. A place where you  
18      could walk up to a feeder and kick a pole. You  
19      could walk up to a customer and shake their hand,  
20      and in fact we did that. Both of those things.  
21      That had defensible assumptions that someone could  
22      read and say, yeah, that makes sense.

23             It was done from the utility  
24      perspective, the customer perspective, and in one  
25      of the really rare cases -- there may be more of

1       these -- a synthesis case where we looked at cost  
2       and benefit sharing between the utility and the  
3       customers.

4               It was done for three different business  
5       scenarios. One was business as usual. Another  
6       one was improved business rules and roles, which  
7       again is the subject of this proceeding. And then  
8       finally, improved rules and technologies.

9       Obviously the CEC, the Department of Energy, EPRI,  
10      many organizations are working on both sides of  
11      this. We can't just focus on trying to improve  
12      the rules, although that would be a great blessing  
13      right there. But we do have to have improved  
14      technologies. And that did make a change, also.

15             The analysis location was Detroit  
16      Edison. They were willing to work with us. It  
17      was in Ann Arbor. It had modest load growth, 4  
18      percent a year, to 3, and then down to 2. It was  
19      a typical feeder; there was nothing unusual about  
20      it. And it had no distributed resources installed  
21      on it at the beginning. One-third commercial;  
22      two-thirds industrial.

23             The way the analysis went is that we  
24      made assumptions as we need them, and no more than  
25      we needed to do, just exactly the assumptions we

1 needed. And background data on the cost and  
2 performance of distributed resources to be looked  
3 at.

4 My firm did the utility analysis; GTI  
5 did the customer analysis. Anyone here from GTI?  
6 Okay. If you want to speak up at some point, I  
7 don't believe you were involved in the study --  
8 okay, I won't put you on the spot. GTI did the  
9 customer analysis. And then we all worked  
10 together on the synthesis of the analysis from the  
11 joint perspective.

12 And now I'm going to make a really  
13 strong statement. Probably the most important  
14 part of this study was the top box. It wasn't the  
15 analysis, it was the assumptions.

16 We have to make a heck of a lot of  
17 assumptions to be able to come with realistic  
18 numbers and defensible numbers for this study. We  
19 needed to know things about the feeder, the  
20 details, the loading, the customers, the CHP  
21 needed at each of those buildings, the rates, the  
22 trend of the rates in the future, the reliability  
23 of the distributed resources. I'm not going to go  
24 any further, except to tell you that the  
25 assumptions list was 28 pages long. And we had no

1 excess assumptions.

2 This tells me that distributed resources  
3 is a tricky game. You need to know a lot of  
4 things. It's much more complicated than central  
5 station, but worth it. So, a lot of data. Very  
6 data intense.

7 Here's the utility result for business  
8 as usual. Cutting to the chase, things, although  
9 the feeder was -- the rating of the feeder was  
10 going to be exceeded by year 2009, DTE was not  
11 convinced in the business-as-usual case, that, in  
12 fact, it would be put in distributed resources.  
13 So the answer for utilities in the business-as-  
14 usual case was let's not put in distributed  
15 resources.

16 If we had small improvements in the  
17 business rules that DTE could rely on, if they had  
18 regulatory permission, for instance, that made a  
19 big difference to them, if they had gained some  
20 technical familiarity with the technologies, if it  
21 had become a standard utility practice by then,  
22 and if there were ways to share the risk and  
23 rewards then in this case, improved business  
24 rules, without changing any technologies  
25 whatsoever, there were very large T&D deferrals

1       that could be taken advantage of.

2               The T&D upgrade was deferred in this  
3       case by seven years. 2.7 megawatts of distributed  
4       resources capacity was put in. That was about 15  
5       percent of the circuit load; and the total net  
6       savings, present value, was \$1 million, including  
7       everything.

8               Going to the customer side, this is a  
9       chart of the bottomline. This is a very long  
10      study. I'm sorry to give the results to you so  
11      quickly. We had eight or nine different types of  
12      buildings that were looked at on this feeder. The  
13      payback with business-as-usual rules were not too  
14      good. Six-year payback was the shortest; and the  
15      longest was 24- or 25-year payback. Not a pretty  
16      picture for distributed resources.

17              If you had slightly improved business  
18      rules, mostly having to do with streamlining the  
19      engineering, the interconnection and lower  
20      installation costs, not changes in the  
21      technologies, these weren't breakthroughs in fuel  
22      cells or microturbines or anything, it didn't need  
23      that. This was just changing the business rules  
24      so that it became a more familiar thing.

25              The paybacks dropped appreciably. Now

1 we had some three- and five-year paybacks. Things  
2 looked pretty reasonable. Those are the bars on  
3 the right-hand side.

4 If you then went to the case of improved  
5 business rules and technologies, now we're talking  
6 some serious market penetration. So the green  
7 bars, as you see them here, now we have paybacks  
8 in some cases of two years and three years. And  
9 we've got very favorable economics on this very  
10 good feeder.

11 Now, I should point out that Detroit's  
12 marginal cost of energy was 2.1 cents. So this is  
13 not an easy place. We were told not to pick an  
14 easy place for distributed resources to make it.  
15 And still, with those types of energy costs, if  
16 you did a good job thinking through all of the  
17 assumptions and finding the right way to use  
18 distributed resources, you could get some fairly  
19 decent market penetration.

20 The bottomline is that the business case  
21 for the utility was triggered by improved business  
22 rules having to do with regulatory permission, and  
23 encouragement to put in distributed resources by  
24 the utility.

25 But the customer cases looked like they

1 really needed some advanced technologies that  
2 really would help a lot. Streamlined siting and  
3 permitting to lower the installation costs was  
4 also a key to opening up that business case.

5 And the joint business case, which I did  
6 not show you, really was even better. Here we  
7 came up with what appeared to be some reasonable  
8 tariff structures that would reward the customer  
9 for turning on the distributed resource exactly  
10 when the utility needed it on. Something like 78  
11 hours a year -- forget exactly how many hours. It  
12 wasn't much.

13 And if the utility would just share half  
14 of their direct savings, then the paybacks dropped  
15 down to one year, two years and three years. So  
16 you really had some exceptional results in the  
17 joint business case. And I wish I had more time  
18 to show you more of the details, but I think you  
19 have some idea.

20 I've shown you starting from a huge  
21 picture of 126 reports; boiling that down to 30,  
22 giving you some idea of which benefits probably  
23 should float to the top of the list. And then  
24 applying looking at the best of those reports  
25 where eight of those benefits were used. And if

1 more of the benefits had been used, maybe the  
2 results would have looked even better.

3 So, with that, thank you very much for  
4 your time. I appreciate it.

5 MR. TOMASHEFSKY: Thank you, Joe. Next  
6 up, if we get this right, we'll have Chris.

7 MR. MARNAY: Hi, I'm Chris Marnay.  
8 Thanks a lot for inviting me to speak today. It's  
9 something of an honor to have the first word in a  
10 very long process. Not quite as sweet as the last  
11 word, perhaps, but nonetheless I consider it an  
12 honor.

13 First of all a word of credit to my  
14 coauthors on this work, Etan, Ranjit and  
15 Christina. And also to the sponsors of this work,  
16 which was the Distributed Energy Office at DOE.  
17 But it does build on a lot of other work that  
18 we've done, as was alluded to earlier, some of  
19 that funded by CEC.

20 First of all just quickly to outline  
21 what I will try to cover here. Basically just a  
22 quick introduction, in fact only one slide. And  
23 then I'm going to give you a kind of benefits  
24 taxonomy, just another list of benefits somewhat  
25 like Joe's. Ones that we worked up in a specific

1 study, which is this one. There is a link to it  
2 on the website if anybody's interested in seeing  
3 the study, itself; you're welcome to look at it.

4 Secondly and then thirdly, I'm just  
5 going to focus on two different specific groups of  
6 benefits that we list there. One related to  
7 prices and economic effects; and then the other  
8 one on reliability and security, a very slipper  
9 issue which I'm sure you will appreciate. And  
10 then finally, a few conclusions.

11 So, just one background slide, which is  
12 this number three. And I think it's actually the  
13 single most important piece of background  
14 information that we need to keep in mind, which is  
15 that electricity usage is growing. And so really  
16 I'm not very sympathetic to the notion that it's  
17 an either/or question, do we have central station  
18 or distributed generation. I mean, we have to  
19 have both. And, in fact, electricity demand is  
20 growing pretty fast.

21 This is my favorite way of looking at  
22 that. Two curves here, and I'm sorry that most  
23 people are looking at a monochrome version of the  
24 slides. The upper flat curve, the blue one, is  
25 over the last 20 years or so in California,

1 consumption of electricity by GDP, or kiloWatt  
2 hours per dollar GDP.

3 As you can see, over that time we've  
4 actually done quite well at making the economy  
5 more efficient. That line has trended down over  
6 time. You might also notice that in times of  
7 economic expansion when turnover equipment is  
8 quicker, then you do get a faster improvement.  
9 And then during recessions, as we are at here  
10 right now, then it does tend to slow down, not  
11 surprising.

12 Then the other curve is much more  
13 disturbing, which is the per capita use of  
14 electricity, right-hand scale. And as you can see  
15 over this period this line has trended up pretty  
16 strongly. So that if you believe that the  
17 population of the state is increasing, together  
18 with this information, it tells you pretty likely  
19 that we're going to have a big increase in  
20 electricity demand.

21 And in fact, since the other line tends  
22 to trend down, assuming a growth rate somewhere  
23 between those two growth rates is a pretty good  
24 guide.

25 So, moving on specifically to this

1 study, the goal of the study in a wider sense was  
2 to look at various kinds of models, methodologies  
3 and so on that could be used to estimate to  
4 quantify the benefits of DG.

5 What I'm reporting on here is just the  
6 first nine pages or so of the report in which we  
7 came up with the list of benefits that you might  
8 want to quantify. And this was really just a way  
9 of setting a framework for our own work on the  
10 methods. But actually, as we did it, I started to  
11 realize that this was actually a valuable exercise  
12 on its own merit.

13 And for one reason, it's a very good  
14 idea just to lay out a framework, just to make  
15 sure that you're not missing anything, make sure  
16 that you've got everything covered.

17 Very particularly, and this very much  
18 related to work on environmental externalities and  
19 other related areas, just because it's very  
20 difficult to estimate a benefit doesn't mean you  
21 should assume it doesn't exist or it's zero. So  
22 the simple mechanism of having a list there and an  
23 empty box to remind you that there's something  
24 that we -- a number we would like to put there, I  
25 think is actually quite important.

1           One thing we tried to do when we wrote  
2       this up was to estimate that -- was to emphasize  
3       that estimates should be around some common point,  
4       so that they're all on a common basis and  
5       comparable.

6           The one that we picked was what if we  
7       get to a 10 percent of new capacity penetration by  
8       DG in 2010 or some other year, so then what's the  
9       incremental benefit of us getting to 10 percent  
10      plus one kiloWatt, or what do we miss if we go to  
11      just 10 percent minus one kiloWatt. But important  
12      to get at kind of marginal effects and around some  
13      established point.

14          And then importantly here, and in  
15      general, of course, we want to identify the areas  
16      where public policy intervention seems to be  
17      justified.

18          So this is the kind of rating system  
19      that we used. When I show you the list of  
20      benefits they're rated along these three  
21      dimensions here, economic size, market likelihood  
22      and tractability. And it's just a very simple  
23      rating system, one to three. And again, for  
24      people that are not seeing this in color, I have  
25      green numbers for positive benefits and red for

1 negative. But that only really applies to the  
2 economic criteria here, that's the only one that  
3 can really go negative.

4 So by economic size here, I just meant  
5 how big of a deal is this. Is this some really  
6 big benefit that we really would like to know  
7 something about, or is it fairly significant. So  
8 we just have a rating small, medium, large.

9 Market likelihood speaks much more to  
10 the direction of public policy intervention and  
11 public policy justification. If this is some kind  
12 of a benefit where we think that the investor or  
13 adopter of the DG equipment is really going to  
14 capture the benefit, him- or herself, then  
15 obviously that's much less justification for  
16 public policy intervention.

17 So a three here, a large degree of  
18 market likelihood, was intended to mean the owner  
19 of the DG captures the benefit. We don't have to  
20 really interfere.

21 And at the other end of the scale, at  
22 one, while obviously some kind of public policy  
23 correction might be justified.

24 And then thirdly, just simply the  
25 tractability. What are the chances that we're

1       able to quantify these benefits. Very much like  
2       Joe said, data very important here.

3               So I'll pause here because there's a lot  
4       of information on this particular slide. So this  
5       shows the first of 17 benefits that we listed;  
6       these are the first nine. I'm going to go into a  
7       bit more detail, as I said, on the first three,  
8       which are orange ones one, two and three; and on  
9       four and five, which are sort of a purple colored  
10      ones.

11             So right here and now I'll just pick out  
12      a couple of the others and just mention them, and  
13      we'll come back to those first five in a bit more  
14      detail.

15             So, looking, for example, at number six,  
16      CHP. Under economic size you can see three.  
17      Obviously that's true, we believe that the CHP  
18      benefit is one of the big economic benefits that  
19      we're likely to get out of DG. Probably not a lot  
20      of argument over that.

21             Under market likelihood I had three  
22      here. And my thinking, or our thinking was that  
23      well, if somebody lowers their energy bill by  
24      applying CHP, that's a benefit that they will,  
25      themselves, capture. Since then other people have

1       said to me, well, that's true, but there are other  
2       kinds of societal external benefits from wider  
3       adoption of CHP, greater energy efficiency, less  
4       import fuel dependency, et cetera. So if we had  
5       it to do again maybe we wouldn't put a three  
6       there, maybe a two. But plenty of room to argue  
7       about this.

8               Then tractability, well, yeah, this is  
9       something, by and large, at least as far as the  
10      internalized part is concerned, that we could  
11      calculate. If we know how much energy somebody  
12      saves we're pretty good at putting a value on  
13      that.

14             The next one, number seven, is noise.  
15      And this is a red number one in the economic  
16      column. Yes, this is a potential negative that we  
17      have to worry about with local generation. I  
18      don't think anybody would disagree with that.

19             Market likelihood low. It's unlikely that  
20      you're going to really subsidize your neighbor  
21      because you're creating noise that he hears. And  
22      tractability sort of medium here.

23             So the spirit of these is pretty broad  
24      ranging, as you can tell. And there's plenty of  
25      opportunity for us to debate them.

1           Reduced T&D losses, voltage support;  
2       obviously these speak somewhat to the grid support  
3       issues and ancillary service provision by DG. The  
4       one other that I would mention here now is this  
5       one number 16 on environmental equity. It's a  
6       strange sounding one. Just a way out, somewhat  
7       out of the mainstream idea, but it basically comes  
8       out of the notion that if we use electricity and  
9       somebody else has to live downstream of the Mojave  
10      plant in Nevada then somehow we're imposing our  
11      externalities on somebody else. If everybody had  
12      their own generator in their own backyard, well,  
13      that seems like it's some kind of an improvement.

14           What's the economic value of this? No  
15      real idea, but we put a low one here. Market  
16      unlikely to take care of it, I would say. And  
17      pretty intractable; these are pretty introspective  
18      questions.

19           So, to look at those first three in a  
20      bit more detail. First of all, they're three  
21      economic ones. First of all, lower cost of  
22      electricity. This is a key one to look at  
23      obviously because the DG adopter being able to  
24      save on his or her utility bill is obviously one  
25      of the key motivators. So something important for

1 us to look at. And that's reflected in this  
2 pretty high economic size there.

3 Yes, by and large, if the customer is  
4 able to lower his own bill, then, yes, that's a  
5 benefit that he captures. And as I said earlier,  
6 yes, this is something pretty tractable, because  
7 we know how much energy costs. We can estimate a  
8 bill savings pretty readily.

9 One area in which there may be some kind  
10 of public policy issue is related to trade. I  
11 mean maybe the optimal DG adoption decision was  
12 predicated on the assumption of some kind of  
13 selling and buying, which may not be completely  
14 legitimate under existing regulations. So there  
15 there's a potential issue.

16 And then number two, price protection.  
17 By this one we basically meant that a DG adopter  
18 is likely to be able to sign a long-term contract  
19 for fuel more readily than they are to be able to  
20 sign a long-term contract for electricity prices.  
21 Potentially could lower the volatility of the cost  
22 that they see, lower their risk to some extent.

23 Even so, you know, there's certain kinds  
24 of regulatory uncertainty, obviously, they're not  
25 going to be able to avoid. And recent changes in

1 the emission standards for DG is a great example  
2 of that. Emissions regulations could certainly  
3 change. But, over all, it seems like there's a  
4 potential benefit here that would help a DG  
5 adopter control their costs, lower their  
6 volatility.

7 This is a more interesting question  
8 related to whether or not owners of DG are likely  
9 to be more price responsive. And many people have  
10 postulated that indeed they are. And we know that  
11 more demand response and demand elasticity in  
12 electricity markets would be an enormously  
13 valuable thing to have. It's a way of taming  
14 market power, and it's a way of lowering price  
15 volatility. So something important to think about  
16 here.

17 And under market likelihood you see we  
18 rated this as only one. It's certainly something  
19 that an individual DG adopter is not really going  
20 to claim the full benefit of. I'm a little  
21 skeptical of this one, as you can tell by the  
22 question mark.

23 So this diagram shows that in a little  
24 more detail. This is a standard economist price  
25 and quantity diagram. The  $Q_s(p)$  is the supply

1 curve here; and we tend to believe that offers  
2 into electricity markets tend to have this hockey  
3 stick shape. Where, for large areas of supply  
4 it's fairly flat; and then at a certain point  
5 offers tend to take off.

6 So if you have a demand curve that looks  
7 like this  $Q_d(p)$  inelastic vertical in the short  
8 run and out far to the right, then you end up with  
9 very high prices of  $(p)_0$ .

10 If you could add some elasticity to this  
11 demand to this market, that is get the demand  
12 curve to slope like  $Q(d)_1$  or  $Q(d)_2$ , then prices  
13 over here can go down quite a lot,  $(p)_1$  to  $(p)_2$ ,  
14 and that's a characteristic of electricity  
15 markets.

16 So if we really believe that DG owners  
17 were going to create this kind of elasticity, then  
18 this would be an interesting benefit to think  
19 about. I'm a bit of a skeptic, as I said, and  
20 that has, in large part, to do with when you get  
21 out to the right-hand side here of the quantity  
22 axis, it's very likely when prices are getting  
23 high that DG owners are already going to be  
24 operating. So, their ability to respond is no  
25 more than anybody else's ability to control demand

1 at that point.

2 And now moving on to reliability, as I  
3 said, this is a really complex area. One thing  
4 that's fairly clear is that there's two different  
5 kinds of reliability, or two different kinds of  
6 benefits. And that's why I have two rows here.  
7 The first one for reliability benefits to the  
8 actual DG adopter, themselves; and then the effect  
9 on reliability on the system as a whole.

10 Again, this is a very important area to  
11 look at, because reliability is likely to be a big  
12 driver of DG adoption, along with bill savings.  
13 Obviously the DG adopter is going to be able to  
14 capture the benefits in terms of improve  
15 reliability in their own service, but then not be  
16 able to capture the benefit from any improvements  
17 or benefits that they deliver into reliability of  
18 the system as a whole. That's why market  
19 likelihood in the first row here reliability is  
20 three. But then very low on the other customers  
21 row, only one.

22 And when you look beyond the individual  
23 customer to net effects of DG on grid reliability  
24 it gets to be an enormously complicated story.  
25 One thing that is clear, however, is that just

1 based on simple probability principles, in a power  
2 system that depends on a large number of small  
3 sources versus a small number of large sources, is  
4 inherently more reliable. I mean that is true  
5 just based on probability. And there's a lot of  
6 established utility methods for estimating that.

7 This is a much more personal view here  
8 of reliability. This is a schematic that I've  
9 developed; there's absolutely no real data here,  
10 let me be completely clear on that. No data were  
11 harmed in the creation of this graphic.

12 (Laughter.)

13 MR. MARNAY: And, once again, because of  
14 the color problem I'll just explain it. The cost  
15 of outages, solid blue line, is the one that goes  
16 from top left to bottom right. The Y axis I have  
17 the total societal cost; this includes everything,  
18 internalized as well as non-internalized costs,  
19 everything. Aesthetic benefits, the total  
20 societal ball of wax.

21 So, basically, if we could improve  
22 reliability, looking at the X axis, and I have a  
23 pseudo-logarithmic scale here starting at about 90  
24 percent reliability on the left, and then perfect  
25 100 percent reliability on the right, that blue

1 line should slope down from left to right. The  
2 more reliable the system the less the cost of  
3 outages. I don't think anybody would disagree  
4 with that.

5 The magenta line that rises from the  
6 left and up to the right is the cost of providing  
7 supply. And I've no idea what this curve looks  
8 like, but the one thing I'm fairly sure about is  
9 that this diagram is incorrect, because I put the  
10 wrong one in the packet. And rather than hitting  
11 the Y axis over on the right side, it should take  
12 off towards the sky, because we're never ever  
13 going to get to 100 percent reliability. So costs  
14 just go through the roof out here at the right-  
15 hand side. You know, where and how much? Pretty  
16 unclear.

17 So the green line, which is the upper --  
18 curve is just the total societal cost or the sum  
19 of those two. Well, any economist is going to  
20 tell you you've picked the point of lowest cost,  
21 so optimum reliability, as I drew it here,  
22 somewhere near the middle. And I certainly  
23 contrived it to come out with a lower level of  
24 reliability than we have today, which is about at  
25 this three 9s point.

1           But the amazing thing about this chart,  
2   I believe, is that we really know nothing about  
3   any of these points, by and large. We have no  
4   idea what these look like.

5           Going further a little bit I  
6   hypothesized that the effect of DG, which is the  
7   dashed line, would tend to be stronger over at the  
8   left; namely, if the system is more unreliable,  
9   more people will adopt DG and it will have a  
10   bigger effect. When you got over reliability  
11   being a big motivator.

12          When you get over to the right-hand  
13   side, maybe DG is going to have less an effect.  
14   And, again, completely arbitrarily I drew it such  
15   that the net effect is to push the optimum level  
16   of reliability to the left.

17          So, coming back to the research  
18   question, I already said the amazing thing about  
19   this diagram really is we know nothing about what  
20   these shapes might look like. Where that little  
21   brown Star of David is, and I apologize again, it  
22   was supposed to be a short line with two fat  
23   arrows at each end, and not a Star of David, and I  
24   hope nobody's offended by that.

25          It's the one point that we have

1 attempted to estimate, which is how much does it  
2 cost us that we don't have a perfectly reliable  
3 system. Even if a perfectly reliable system is  
4 not a very realistic goal, that's the way we tend  
5 to judge unreliability.

6 Recent study by my colleagues at  
7 Berkeley Lab, Christina Lacomme (phonetic) again  
8 and Joe Eto, came up with a number of about 26  
9 billion for that vertical distance. And there's  
10 plenty of other estimates out there in the hundred  
11 billion dollar range and up to a few hundred  
12 billion. But, in fact, that's about the only  
13 point that we attempted to estimate here.

14 All that argument is just based on the  
15 notion that we can have a universal quality and  
16 reliability of service, and we can pick a  
17 universal quality. But there's something that I  
18 think is actually more important about distributed  
19 gen, which is when the generation gets closer to  
20 the load, particularly in a kind of microgrid  
21 context, then there's the hope of tailoring the  
22 reliability and quality of the service better to  
23 the requirements of the end use. And like  
24 everything else in economics, we know that if we  
25 can tailor something to the requirements, we end

1 up with a better result.

2 So, what I've done here is just taken  
3 some data on the contribution to energy use and  
4 peak of various end uses in California and I've  
5 totally, by introspection alone, just stacked them  
6 up in what I think might be the importance to them  
7 of a high reliability of service. This data came  
8 from my colleagues at the lab, Rich Brown and John  
9 Koomey. They didn't have a very convenient  
10 category of highly sensitive load, which would  
11 have made my life easier.

12 So I just put office equipment up there  
13 at the top. And the dashed line across the top is  
14 just the level of reliability that we try to  
15 provide right now. And we attempt to provide a  
16 universal quality and reliability of service to  
17 everybody at every single outlet.

18 But we know that it's not good enough  
19 for certain kinds of sensitive end uses, so you  
20 can see that the top box is partially not covered  
21 there. And one of the loads in that top uncovered  
22 box we know because everywhere we see when there's  
23 a UPS system or a backup generator sitting next to  
24 it. So we know the loads that aren't getting an  
25 adequate reliability of service.

1           So, the argument here is simply that if  
2       we were able to provide a quality and reliability  
3       of service better tailored to each of these end  
4       loads, then maybe the global universal quality of  
5       service could again be pushed down somehow. Could  
6       we live with lower utility quality of service.  
7       And, you know, would that deliver us some big cost  
8       savings? I think we actually don't know right  
9       now.

10           Okay, just one word on security. I  
11       think I've already gone over time. Obviously  
12       security of the grid is something we're very  
13       concerned about now, and the grid's are very  
14       vulnerable target. To the extent that sensitive  
15       loads could be provided for independently of the  
16       grid, obviously it makes it a less attractive  
17       target, makes us able to survive outages with less  
18       consequences.

19           So, basically I've argued -- last  
20       slide -- a comprehensive and consistent approach,  
21       as Joe already told us, is needed to estimating  
22       the benefits. I think it's valuable just to, as I  
23       said, make the simple expedient of creating a list  
24       and sticking to it, just to remind yourself of  
25       everything that's on it.

1           Many of the issues, very complex and  
2           imponderable. I think that effects on the grid  
3           and reliability pretty high on that list.

4           And then one final thought that I wanted  
5           to leave you with, which is that amongst all this  
6           detail on estimating individual benefits and so  
7           on, probably we should remind ourselves that we  
8           are talking about a major paradigm shift here,  
9           really going from a more distributed to a less  
10          distributed power system, and so there are going  
11          to be all kinds of consequences, you know, good  
12          and bad, that we actually can't anticipate at this  
13          time. Just like electrification of the economy or  
14          other large changes of that magnitude.

15          MR. TOMASHEFSKY: Thank you, Chris.  
16          Next up is Snuller Price. He's doing double duty  
17          this afternoon; so this will be his first of two  
18          presentations.

19          MR. PRICE: Thanks, Scott. In this  
20          first section what I wanted to talk about and  
21          summarize is a sort of parallel proceeding at the  
22          CPUC on avoided costs for the energy efficiency  
23          program. Although this is a panel on the sort of  
24          existing or past studies, this is still an ongoing  
25          proceeding at the CPUC with workshops later this

1 summer in June. And I'm going to try to do the  
2 quick summary.

3 I was, I think, behind this podium two  
4 weeks ago with a 30-minute version of this. So I  
5 apologize if you've seen a lot of these slides  
6 already. This is the 20-minute version.

7 The avoided costs, and for those that  
8 are sort of new in this area, is another way of  
9 saying well, what are the benefits of doing it --  
10 in this case, energy efficiency. And the benefits  
11 for evaluating the public goods charge funded  
12 efficiency programs have to be quantified in order  
13 to be able to do that analysis for the efficiency  
14 programs.

15 So what I'm going to present to you is  
16 how those numbers look for the efficiency side.  
17 It's important to keep in mind that these numbers  
18 were developed for the efficiency programs. They  
19 were developed with a stakeholder group that  
20 included a lot of groups, including the utilities  
21 and CPUC. Also NRDC, ORA, a number of groups have  
22 looked at these. And that workshop has been  
23 progressing as focused on applications to energy  
24 efficiency.

25 So one of the natural questions that you

1 can write and ask is, well, how do these avoided  
2 costs apply to distributed generation. Seems like  
3 a natural question. And that's actually a topic  
4 that's going to be discussed in the June workshops  
5 of the CPUC. So, if that's your question I can't  
6 answer that yet.

7 I wanted to give another kind of a  
8 little background with the relationship to Title  
9 24, which is the building standards process here  
10 that the California Energy Commission has.  
11 Because with support from PG&E and others through  
12 the Title 24 standards process, there's something  
13 that's similar in terms of avoided costs and the  
14 shapes that I'm going to talk about for that.

15 So, with the CPUC avoided costs for new  
16 efficiency measures, which include retrofit and  
17 new construction, with the building standards in  
18 the state on energy efficiency with similar  
19 methodologies, we think we've kind of got at least  
20 some uniformity among efficiency pieces.

21 So what does this look like? What I've  
22 got here is kind of jumping to a picture that I  
23 like to use to sort of show what we did for the  
24 energy efficiency. And for those who have done  
25 this type of thing in the past, this picture looks

1 quite a bit different.

2 The existing set of avoided costs for  
3 energy efficiency that had been done under the  
4 CPUC had really one number for a number of  
5 different categories for the whole state and for  
6 the whole year. So, just sort of one number,  
7 dollar per kiloWatt hour.

8 And what we tried to do was really  
9 disaggregate each of those cost components into  
10 time -- there's an actual number for each hour of  
11 the year -- by area. And what we did was divide  
12 by climate zones that are used in order to  
13 estimate how efficiency measures will reduce load.  
14 And then for these individual categories.

15 Now, the components that we have on  
16 here, this blue piece -- and we're going to be  
17 talking about each of these components in a little  
18 more detail -- the blue piece here are avoided  
19 generation costs with losses. The green piece is  
20 our environmental externality. The red piece, the  
21 reliability externality. And on that reliability  
22 that's a bulk system ancillary services type of  
23 reliability definition. And the gray piece is  
24 labeled here as price elasticity of demand  
25 externality. And what that really is, is

1 wholesale market price effects.

2 Now, notice on Wednesday here I've got a  
3 yellow piece, the T&D cost, okay. What we found  
4 by looking at utility loads and temperatures is  
5 that really the transmission distribution capacity  
6 projects are driven by those days that have the  
7 hottest times. So in order to estimate the T&D  
8 avoided costs -- and I'm going to talk about this  
9 in a little more detail -- we use the weather  
10 files by climate zone in the state to allocate  
11 those costs to hours.

12 Back to the relationship with the past  
13 avoided costs, this reliability externality piece  
14 and the elasticity of demand piece are new. The  
15 other pieces have been a part of the efficiency  
16 avoided costs in the past for Title 24, as well.

17 Here's a quick chart that shows the  
18 summary of the project requirements. And what I  
19 wanted to get to is the level of disaggregation  
20 that we've got. Under the sort of traditional  
21 avoided costs I've got electric generation,  
22 electric T&D. We also did natural gas avoided  
23 costs. We have natural gas procurement, natural  
24 gas transportation.

25 Electric generation and where the x's

1        were was what CPUC was really looking for in terms  
2        of the level of disaggregation. They were looking  
3        for hourly estimates of avoided generation costs.  
4        And we said that that is appropriate. And  
5        recommended also that those vary by location in  
6        the state.

7                So the R was our recommendation, and  
8        that's what's in the draft set of avoided costs  
9        that are out there now. And I should mention,  
10       these numbers, I believe, are going to be on the  
11       CPUC website if they're not already. And  
12       certainly there's a very large report, 300 pages  
13       or something, about each of these in detail that's  
14       on their website.

15               Electric T&D piece, as I mentioned, vary  
16       by hour and location. Natural gas procurement is  
17       more monthly, monthly variation and forward  
18       natural gas prices. But they also vary by  
19       location, northern and southern California.

20               The environmental externality,  
21       reliability adder and demand reduction benefit and  
22       the wholesale market prices are generally annual  
23       values. But a lot of those are multipliers to the  
24       market price, which varies by hour. So you end up  
25       actually with some hourly variation.

1 I don't want to spend a lot of time on  
2 the formulation, but this gives you a sense of  
3 which of those pieces are included and how they  
4 add up in the analysis.

5 On the electric said we have the  
6 commodity, ancillary services. This market  
7 multiplier; losses. And then we've got an add  
8 term. T&D costs and environmental externalities.  
9 So we've got all those pieces sort of under the  
10 electric side. And a similar set of components  
11 for natural gas.

12 What I want to do now is sort of walk  
13 through how we did each of those components. What  
14 our approach was, was to estimate each of these  
15 components by area, by hour and then add them up.

16 The first set, market price forecast,  
17 our approach on the market price was really to  
18 look at the market. There's been a lot of work in  
19 the past on, you know, production cost models and  
20 so on. Our feeling was, wow, we've got this great  
21 source of data out there, at least on the market  
22 prices. You can go out and you can get forward  
23 price curves. So why not use that. Of course, at  
24 some point that breaks down. In about 2008 or so  
25 you get either no contracts or contracts with so

1 little liquidity that you have to move to  
2 something that I've titled here, LRMC, which is  
3 more of a long-run marginal cost based on the  
4 CEC's forecast of natural gas prices.

5 Putting those two pieces together, along  
6 with assumptions of the costs of new installed  
7 generation capacity, and again we used some  
8 Commission numbers, we got a market price forecast  
9 for northern California and for southern  
10 California over time.

11 This is just the annual average number  
12 for one example. This we allocated to hour,  
13 actually, based on historical market price shapes  
14 from the PX during what we call the functional  
15 market period.

16 On top of the market prices we had  
17 ancillary service costs. We estimated that as a  
18 percentage of what the market price looks like,  
19 with some regression analysis. What we found is  
20 it's really pretty remarkably stable at around 3  
21 percent of the commodity prices. And, again,  
22 there's a lot more detail in the report on how  
23 this works out, but if you use that number as a  
24 multiplier you get higher ancillary services costs  
25 during higher priced periods. And it tends to

1 track pretty well.

2 The third component is this market  
3 elasticity estimate. What this is, is if we can  
4 reduce what the peak loads are through our  
5 efficiency measures, how is that going to result  
6 in a different wholesale market clearing price in  
7 the state.

8 Again, we did pretty considerable  
9 regression analysis looking at this, and applied  
10 what we thought and saw from our regression  
11 analysis there to the estimated residual net short  
12 positions of the major utilities in the state.  
13 Now, the RNS assumption that we used, because we  
14 didn't get detailed procurement data from  
15 utilities, nor do we really need it for this, was  
16 5 percent.

17 So although there is a market price  
18 effect, a majority of our energy is already  
19 purchased through long-term bilateral contracts  
20 and what-have-you; and so that effect turns out  
21 net to be about 7 percent increase in the market  
22 price estimate.

23 T&D avoided costs, and I'm sorry this  
24 map turned out to be pretty poor in the  
25 duplication, what I wanted to give you a sense for

1       though was different climate zones. We carved the  
2       state up into -- we didn't, the California Energy  
3       Commission had established climate zones for  
4       different areas in the state for the building  
5       standards work.

6               And what we did was overlay that with  
7       investment cost data from the utility filings.  
8       And estimated where the T&D avoided costs were for  
9       each of those climate zones. So that gets you to  
10      \$1 per kW number.

11             Here on my map the red areas have a  
12      higher avoided cost, somewhere in the range -- and  
13      I'm sorry there's no scale on here -- but  
14      somewhere in the range of \$60 or something like  
15      that, per kW year. And detailed numbers are in  
16      the report. Down to very low areas, low cost  
17      areas like San Francisco Bay Area, which were more  
18      in the \$8 range.

19             Those costs were then allocated based on  
20      climate data. Peakier areas that are in the  
21      Central Valley that have much more kind of extreme  
22      days, those costs end up getting allocated a fewer  
23      number of hours, which gives you higher incentive  
24      for efficiency during those critical peak heat  
25      storm days.

1           If you go to the coast and you have a  
2   lot of mild days, those T&D costs tend to be  
3   allocated over across, you know, a whole bunch of  
4   hours, and tends to be quite lower on a per  
5   kiloWatt hour savings metric for efficiency.

6           Emissions. A couple things on  
7   environmental externality piece. We included  
8   avoided NOx, PM10 and CO2 emissions. Okay. NOx  
9   and PM10 have market prices that you can look at  
10   and lean on for avoided energy consumption. So we  
11   went and looked at those markets and those market  
12   prices.

13           CO2 emissions are different. And they  
14   were added in, even though there's not a mandate  
15   on CO2 or prices for CO2 offsets that are mandated  
16   in the state, so as a policy for efficiency those  
17   are included. And those actually make up a  
18   majority of this cost curve that you're looking at  
19   here.

20           For each hour of the year we had an  
21   estimated heat rate that was implied by the market  
22   price. We used that heat rate to follow what that  
23   meant in terms of what the marginal unit is, what  
24   those average emission rates would look like, and  
25   then translated that to dollars per megawatt hour

1 benefit of reduced consumption during that hour.

2 I know I'm going quickly, but hopefully  
3 that makes sense.

4 So what does this look like when you  
5 start to add it up and you look at a whole  
6 picture? And what I have here is just for one  
7 example place. This is in PG&E's San Jose  
8 planning division, which is in the climate zone  
9 there, South Bay. And I've got a picture of the  
10 whole year's worth of avoided costs. And I'm  
11 showing the maximum value by month and hour for  
12 the whole year.

13 So what you see is I've got hours 1  
14 through 24, and months 1 through 12. And what you  
15 find out when you look at a curve like this is  
16 wow, this landscape is not looking flat. Okay.  
17 What we've got here are a pretty considerable peak  
18 in the middle of the day in the middle of the  
19 summer. And that's based on the weather profile  
20 in that area, the expected T&D expenditures for  
21 capacity in that area, and a summation of the  
22 other factors that I talked about.

23 We just looked at a whole year. Well,  
24 how does it look like if we just zoom in on two or  
25 three days? And here's a picture of that. Again,

1 I've got the same components we had earlier in the  
2 stylized chart, but these are the actual values  
3 that we have for this one example, again in the  
4 San Jose planning division.

5 The layers are ordered in the same way  
6 that the legend is, so although some are small you  
7 can kind of get a sense of where you're at. Not  
8 sure how well that duplicated, but I think these  
9 presentations are available on the web, as well.  
10 Get detail.

11 So, what does this do for efficiency?  
12 Now, remember we used to have just one value, one  
13 flat value for each of these components for the  
14 state. And I've got results for three types of  
15 example measures on the efficiency side, using  
16 those existing avoided costs. And those are the  
17 red bars here.

18 And what you find out is that the  
19 avoided cost is something like \$78 per megawatt  
20 hour levelized value. For air conditioning, which  
21 saves, obviously, energy during the hot periods;  
22 for outdoor lighting, which obviously saves energy  
23 during the middle of the night; and refrigeration,  
24 which saves energy 24/7. You get the same level  
25 of avoided costs.

1                   Now, if you recompute those values of  
2     those savings for air conditioning, outdoor  
3     lighting, refrigeration with these new avoided  
4     costs what you find out is that you get a  
5     significantly higher incentive to reduce air  
6     conditioning load versus refrigeration or outdoor  
7     lighting. And the number moves from \$78 in this  
8     case to about \$136 or something like that. So  
9     what this does is it really shifts more value  
10    towards peak load reductions for the efficiency  
11    program.

12                  I think that is the last slide and we're  
13    going to take questions after the panel.

14                  MR. TOMASHEFSKY: Thank you, Snuller.  
15    As Carl comes up I just want to remind those who  
16    are listening on the web that each of these  
17    presentations are available on the website and  
18    downloadable. So if you need to follow along, you  
19    can do so.

20                  MR. SILSBEE: Thank you. I appreciate  
21    being here today. We'll be filing more extensive  
22    comments on the issues that are the subject of  
23    today's workshop in a week and a half, on the  
24    17th. But I'd like to share the highlights with  
25    you today.

1           What I'll do is I'll step back from the  
2 microphone and talk a little louder. Does that  
3 work for you? And then can you still hear me?  
4 No? Okay , I'll try to get modulated. Thank you.

5           Let me start with a key observation.  
6 There's a world of difference between, for  
7 example, a rooftop solar unit, a large industrial  
8 cogen unit or a diesel engine used by, let's say,  
9 a hospital as backup when there's an outage.

10          When somebody talks about DG can do  
11 this, or DG can do that, I think you need to ask  
12 the question, well, what kind of DG are you  
13 talking about. Because the benefits and the costs  
14 associated with the DG unit are going to be very  
15 much a function of the technology and the  
16 application of that DG unit.

17          As we move forward in this proceeding we  
18 need to step away from a one-size-fits-all  
19 thinking about DG, and really inquire, as we're  
20 asking about benefits and costs, what are the  
21 specific technologies and applications that are at  
22 issue here. And we need to tailor policies that  
23 are appropriate for those kinds of technologies  
24 and applications.

25          Because of the variety I just talked

1 about DG can serve a number of different roles.  
2 Most of the DG applications today are installed by  
3 customers and they're either for bill savings,  
4 units that would run many hours of the year, or  
5 they're backup for reliability purposes, usually  
6 units that will only run when there's an outage.

7 Over the last few years we've worked on  
8 modifying our interconnection rules to help remove  
9 barriers to customer DG to better enable customers  
10 to make choices in installing DG for self  
11 generation purposes.

12 Another potential role is for DG as a  
13 grid resource, something that the utilities would  
14 pursue as an alternative to investment in  
15 distribution feeders or distribution circuits.

16 Our expectation, and I think this is  
17 confirmed by some of the other panel presentations  
18 today, is the DG in that function is likely to be  
19 highly localized and of a relatively short time  
20 duration. In other words, a deferral of  
21 investment, not necessarily a replacement of  
22 investment.

23 One of the reasons for that, I think, as  
24 I look at the numbers, is that most DG units just  
25 simply can't match the 99.99 percent reliability

1       that the distribution grid now provides to  
2       customers. What that means is that DG units are  
3       more likely to serve what I might call a topping-  
4       off function. In other words creating an ability  
5       to improve reliability in a problem area by being  
6       available at times when the circuit would  
7       otherwise be unable to fully supply the needs of  
8       the customers.

9               An interesting idea that has come out  
10       through the CPUC process and recent decisions is  
11       this notion of physical assurance. I think that  
12       creates a very interesting opportunity for  
13       customers. In other words if you have a self  
14       generation unit that you would ordinarily rely  
15       upon, but you are connected still to the grid, you  
16       would provide the assurance to the utility that if  
17       your DG unit drops that you can be interrupted so  
18       that the utility is not forced to rely on  
19       supplying backup power to the DG unit to meet the  
20       needs at a time when the DG unit is otherwise  
21       unavailable.

22              What that does is it allows the customer  
23       to tailor the level of reliability that they want  
24       for the service that's provided them.

25              Next let me go through some points that

1 I think you all know very well. Unfortunately  
2 they're sometimes easy to overlook in practice.  
3 First, let me stress that DG needs to be looked  
4 at from different perspectives. Everyone who has  
5 gone through the DSM standard practice manual  
6 understands this basic analytical structure.

7 A DG resource would reduce utility costs  
8 and will also reduce the customers' bills. And,  
9 of course, these benefits are not additive.  
10 They're just the same manifestation of cost  
11 savings, but from two different perspectives; the  
12 utility ratepayer perspective, and the individual  
13 customer perspective.

14 Another important issue is we need to be  
15 very careful when we start ranking and listing  
16 benefits that we not engage in double counting.  
17 The CEC last August released some cost estimates  
18 for different forms of central station technology.  
19 For instance, there's a CT cost estimate, and a  
20 CCGT cost estimate. Those resources already take  
21 into account interconnection costs, necessary  
22 environmental controls and purchase of  
23 environmental offsets.

24 So it wouldn't be appropriate to  
25 separately credit a DG unit with the capability of

1       avoiding the capacity cost of a CT proxy and also  
2       crediting it with emission values, because those  
3       are already captured in the cost of the capacity  
4       proxy.

5               And I think as we go through lists of DG  
6       benefits we have to really ask ourselves, is this  
7       somehow captured through some other benefit. And  
8       critically look at the different benefits from  
9       that perspective.

10              And just a final point. We shouldn't  
11      leave out the costs which are charged to the DG  
12      customer for services that are provided by the  
13      utility grid. Standby charges, backup service  
14      charges are intended to be cost-based. And they  
15      should be part of any analysis of DG units from  
16      the customer perspective.

17              Let me close with our viewpoint on DG.  
18      Most importantly, as I suggested earlier, we want  
19      to support cost effective customer choice for DG.  
20      What that means to us is sending the appropriate  
21      price signals for DG through our rate designs. We  
22      do not want to artificially encourage DG. We do  
23      not want to discourage cost effective DG.

24              We have worked hard to try to improve  
25      the interconnection process, to make it simpler

1 and less expensive to DG customers. We are  
2 charged with insuring adequate reliability to our  
3 customers. We need to protect the assets we have  
4 out in the field. And we need to protect public  
5 and employee safety. So those remain important  
6 considerations in the interconnection process.

7 We'd like any subsidies that are  
8 provided to DG in the interest of promoting the  
9 technologies or demonstrating them to be explicit.  
10 We'd like them to be consistent with California's  
11 adopted policy objectives. And essentially and  
12 eventually we'd like to be accountable to our  
13 customers that we've spent the money on subsidies  
14 wisely.

15 Second, we're now considering DG and the  
16 distribution planning process. And I'd just like  
17 to make a point. That under cost-of-service  
18 ratemaking we have an obligation and a financial  
19 incentive to find least-cost solutions. Between  
20 rate cases any savings we can find enter to the  
21 shareholders. And then when things are trued up  
22 in the next ratecase they they're flowed back to  
23 our customers. And that does create an  
24 opportunity for us to look for solutions that are  
25 least cost. And we intend to do that with regard

1 to distribution DG.

2 Thank you.

3 MR. TOMASHEFSKY: Thank you, Carl. Last  
4 up is Kevin Duggan.

5 MR. DUGGAN: Well, I'd like to start by  
6 thanking the Commissions for inviting me to  
7 participate in this workshop today. I'm rather  
8 honored, I think, to be on a panel with people who  
9 have contributed so much to this issue of  
10 distributed generation, and who have given such a  
11 large amount of thought to it. I'm rather -- I  
12 feel I have a daunting task following these  
13 people. But, well, I'll try.

14 I represent the California Clean DG  
15 Coalition. This is an ad hoc group of parties  
16 interested in distributed generation. It  
17 includes, among others, Chevron Energy Solutions,  
18 Cummins, Incorporated, RealEnergy and Capstone  
19 Turbine Corporation. I mention those people  
20 because I know that representatives of those  
21 companies are here today.

22 The Coalition has been involved actively  
23 in a number of proceedings before the PUC over the  
24 last maybe two years, and I'm very pleased to be  
25 here representing the Coalition today.

1           The focus of the presentation that I'd  
2     like to do today is firstly and very briefly to  
3     summarize what the DG Coalition and DG parties  
4     have presented to the Public Utilities Commission  
5     previously on the benefits basically of  
6     distributed generation.

7           And then I wanted to go to another  
8     point, and that is to try and see if we could  
9     learn anything out of the recent experiences in  
10    California that might be relevant to understanding  
11    the benefits distributed generation can provide.  
12    And I'll get to that later.

13          I've got a little note at the bottom  
14    here of some assumptions, because as I re-read  
15    this I felt it was useful to at least bring out  
16    the implicit assumptions.

17          And they are I'm assuming that the  
18    electricity system will continue to be regulated.  
19    That doesn't mean necessarily that it will or will  
20    not be subject to some level of competition. But  
21    it does mean, I think, that the electricity system  
22    will have a special set of regulations of some  
23    sort as we go forward.

24          And the other thing that I believe will  
25    be the case and is implicit in this is that the

1 grid will be a central part of the electricity  
2 system. And that that will continue to be the  
3 case.

4 So, this slide presents two of the  
5 studies that have been discussed presented by  
6 distributed generation parties to the PUC in  
7 recent times. These two studies were either  
8 presented or referenced in the departing load cost  
9 responsibility surcharge proceeding.

10 Now, a lot of people today have already  
11 talked about the components that make up these  
12 benefits here, so I'm not going to talk about  
13 that. The only thing that I'd like to highlight  
14 from this particular slide is that you can see  
15 that the benefits both sides calculate are not  
16 trivial; something between 3 and 4 cents per kWh.

17 This was a part of the cost  
18 responsibility surcharge proceeding that  
19 distributed generation people submitted on. Prior  
20 to their proceeding, of course, there was another  
21 Public Utilities Commission proceeding which was  
22 looking at issues to do with distributed  
23 generation within the utility planning process. I  
24 think early last year a decision came out on that,  
25 which did recognize that there was some role for

1 distributed generation. I think as long as it was  
2 cost competitive and as long as it was at least as  
3 reliable as the grid system. Or alternatively, as  
4 long as physical assurance was provided.

5 But that's about as far, I think, as --  
6 I don't know, I'm sort of characterizing the  
7 conclusions very briefly -- but that's, in  
8 essence, where I understand the Public Utilities  
9 Commission has got on incorporating DG  
10 specifically in the overall electric system.

11 Now, I want to go on to the second part  
12 of the things I'd like to do which I think is more  
13 interesting. And then as I prepared for this  
14 presentation I tried to think about how the  
15 experiences we have had basically since AB-1890,  
16 the attempt to restructure the industry and the  
17 subsequent events, the electricity crisis, how  
18 things that were fleshed out from out of the  
19 electricity system from those experiences; how  
20 they may have been changed by how distributed  
21 generation might have interplayed with those  
22 outcomes.

23 And so before I look at that I thought  
24 it useful just to highlight the things that I felt  
25 were fleshed out. The ratepayer guarantee. This

1       seems to be an assumption that the ratepayer will  
2       insure that the utility will receive return on the  
3       activities it undertakes, really at the direction  
4       of the regulators.

5               And the cost of the guarantee is  
6       manifest in recent years in the form of CTC  
7       charges and departing load charges.

8       Interestingly, the ratepayer guarantee, I think,  
9       is now transferred into a guarantee over the  
10      Department of Water Resources long-term contracts.  
11      And so the ratepayer is now paying various fees,  
12      gets incorporated into the departing load charges  
13      and things of that nature.

14             Another thing that we learned is the  
15      relatively static nature of the asset mix, the  
16      generation mix that the electricity system has.  
17      There are long lead times to build new capacity.  
18      It takes a long time for assets to fully recover  
19      their costs. And, in effect, you see how slow it  
20      is to adopt new technologies when you look at  
21      things like the efficiency across the nation of  
22      thermal generation. It's been pretty static for  
23      quite a long time despite improvements in the  
24      technology. So this is another characteristic of  
25      the electricity system.

1           Average cost pricing within customer  
2       classes. I'm going to talk a little bit more  
3       about that later. I don't want to talk too much  
4       about that right now. What I can say about this  
5       is that customers within a class don't  
6       necessarily, the price they pay for that doesn't  
7       necessarily reflect the true cost. And it goes to  
8       the point of Chris' supply curves which are  
9       hockey-sticked, that everyone pays the same price.

10           The fourth point I've got here is  
11       centralized decisionmaking with concentrated  
12       supplies, which some people say was really the  
13       cause of our electricity crisis. Too few players  
14       with too much power were working.

15           A fifth point I've got here is that the  
16       investments are very large and take a long time to  
17       bring the new assets into the marketplace. It  
18       takes a long time to build new generation. And  
19       even longer to build new transmission distribution  
20       facilities.

21           The last point I've got here is  
22       emissions, but people have just discussed that  
23       point I think already, and so I don't want to talk  
24       about that again.

25           My purpose in listing these

1 characteristics is to see if DG could have helped  
2 ameliorate the effects of some of these  
3 characteristics. It must be said that it's not  
4 my view, or it's not the view of the Coalition, I  
5 think, that the electric grid based system should  
6 be replaced by DG. Most DG technologies are built  
7 to operate parallel with the grid.

8 And so they at least implicitly have  
9 this fundamental view that the grid is a central  
10 part of what's going on here. So please don't  
11 think that anything I'm doing here is advocating  
12 anything other than that.

13 So, looking at how DG may play into the,  
14 or help ameliorate some of the effects, and  
15 therefore provide some benefit to the system, how  
16 would DG help reduce the potential costs of  
17 ratepayer guarantees. As already mentioned,  
18 already the guarantee results in various charges,  
19 CTC charges, departing load charges, those sorts  
20 of things.

21 The CTC charges are the result of  
22 investments that have become uneconomic. QFs are  
23 among those things that result in CTC charges.  
24 But these investments are often long term in their  
25 nature and they cannot be terminated.

1           As I understand, they include things  
2     like the nuclear power plants, the QFs facilities,  
3     which have attained a 30-year life expectancies  
4     and paybacks. Now, of course, distributed  
5     generation still today can't alter those  
6     historical investments, but it can help to reduce  
7     the risk that future assets will become strained  
8     and long-term and will require CTC charges.

9           Many distributed generation systems have  
10    paybacks of two to five years. And this  
11    relatively short payback period reflects the  
12    customers' requirements. You see this requirement  
13    reflected in comments that businesses make  
14    regarding the core/noncore where they're saying  
15    even five years commitment for power supply is too  
16    long. Today's business requirements are for a  
17    very short and quick rapid change. The only  
18    constant business today is change, in essence.

19          So they look for, and in effect they  
20    come to us and ask for a payback on distributed  
21    generation that's two, three years. They want a  
22    very quick turnaround. So adding more distributed  
23    generation to the electric supply mix will reduce  
24    the average economic life of our electricity  
25    systems assets. And thereby will help to mitigate

1 the risk of a future long-term stranded assets and  
2 the costs associated with them.

3 It's one way that I think adding to the  
4 mix and diversifying the mix of generating assets  
5 and electricity assets can provide a benefit, I  
6 guess.

7 DG helps avoid costly static asset  
8 mixes. The quicker payback of most DG means that  
9 the benefits of the investments can be delivered  
10 more rapidly than otherwise. This enables the  
11 asset mix to take on a more dynamic characteristic  
12 enabling the electric system to adopt new  
13 technologies, including higher efficiency  
14 technologies, more quickly.

15 DG also brings a level of diversity to  
16 the generation mix. It reduces the reliance on  
17 limited range of technology and this adds to the  
18 diversity of the generation base. Which is  
19 generally seen as a good thing for reliability and  
20 robustness of the system.

21 Now this is to do with the average cost  
22 pricing approach of -- and I'm sorry to have a  
23 graphical representation here; I find graphs are  
24 either for some people too complex, and so I  
25 apologize to those people. And for people who

1 think that I'm over-simplifying electric rates, I  
2 apologize to those people.

3 Maybe this graph is just an apology, but  
4 it's really attempting to say that there are -- at  
5 the margin there are some customers whose costs of  
6 getting power to them is higher than other  
7 customers. All of those customers within the same  
8 rate class pay the same price. The lower cost  
9 customers are essentially providing a subsidy to  
10 the higher cost customers.

11 So the customer, themselves, does not see  
12 the true cost of supply. And often will see that  
13 the cost of using distributed generation maybe  
14 actually be a little higher than the cost of  
15 taking power from the grid.

16 Now, the overall system could benefit,  
17 though, by installing for those marginal customers  
18 distributed generation which is lower than the  
19 marginal cost of meeting their needs through grid  
20 expansion or substation expansion. And so the  
21 average price across the whole customer base could  
22 be lowered by using distributed generation to meet  
23 those marginal customer needs. That's the  
24 intention of that graph that may be more complex  
25 than need be.

1           So, let's move on from there. It's too  
2   late for graphs. DG can reduce the demands on  
3   centralized decisionmaking. This is something  
4   that we see now with, you know, the procurement  
5   proceeding that decisions are made central. The  
6   risk of centralized decisionmaking is that we end  
7   up with decisions that are too much alike. And if  
8   those decisions turn out to be inappropriate, then  
9   we have a major problem.

10           DG can be implemented at the customer  
11   level. It brings more players into the process of  
12   determining how the state meets its energy needs.  
13   People will make different and independent  
14   decisions which will make for a more diverse set  
15   of decisions, and a more robust energy supply  
16   system. I think that's something of value, also.

17           Because DG is small it can reduce the  
18   need to oversize grid assets and thereby defer  
19   costs. This is essentially part of that deferred  
20   asset argument. Another important benefit of  
21   small size of DG is that it can be deployed  
22   relatively quickly. DG capacity can be installed  
23   and operated in a matter of months, whereas large  
24   generating facilities, and to a greater extent,  
25   transmission upgrades, can take years before they

1       become productive. So, the effect of that sort of  
2       benefit.

3               The other thing, and this is a picture I  
4       took from the economists, I sort of planted in  
5       here. But I think it's important. It's about  
6       where the next generation distribution system is.  
7       And what does it look like. And what you see here  
8       is a picture that shows -- the top one is the sort  
9       of conventional system where the central power  
10      plant is at the center of the picture.

11             And a lot of people are talking today  
12      about a new self-healing sort of internet-based  
13      kind of an electricity system. It's a system  
14      where now the center of the picture is replaced by  
15      this control center, which is a computer that's  
16      intelligently communicating between loads and  
17      generation. Generations are all sorts of types;  
18      we've got distributed generation, wind; we've got  
19      central power plants.

20             This is a self-healing rerouting of  
21      power to main problems. This is a more highly  
22      reliable system than we have today. Now, the  
23      reason why I put this here is because distributed  
24      generation not only plays a role in this  
25      particular model, but the distributed generation

1 technologies that are around today, including fuel  
2 cells and microturbines and photovoltaics, all  
3 have the digital electronics embedded in them  
4 today. That that will enable this kind of a new  
5 next generation grid to actually function and  
6 communicate.

7 I know, talking about Capstone  
8 specifically, our microturbines, and I think it's  
9 the case with a lot of technologies, microturbines  
10 are already set up so that we can communicate with  
11 them and operate those machines remotely. So  
12 that's something of a vision of the future.  
13 Distributed generation technologies can help us  
14 get there.

15 This is my last slide. There are no  
16 numbers in this slide, although it does -- I'm  
17 sorry, Joe, it does say quantifying the benefits,  
18 but there are no numbers because -- reminds me of  
19 this. You know, there are no numbers in here  
20 because I'm actually an economist by training, and  
21 as I read recently there are three types of  
22 economists. Those who can count and those who  
23 can't.

24 (Laughter.)

25 MR. DUGGAN: But what I was trying to do

1 in this slide was to say that we have had some  
2 experiences in California that have fleshed out  
3 some costs involved in our electricity system.  
4 You know, the cost of the guarantee has been  
5 quantified to some degree through departing load  
6 charges and other charges.

7 And there are other things that have  
8 been happening in California. You know, the long-  
9 term contracts and departing load charges, all  
10 these sorts of things. It's information that  
11 we've got out of our recent experiences. And I  
12 think it would be very useful and very insightful  
13 to look at that information and to see what it  
14 tells about the costs of some of the things that  
15 we could address potentially through the use of  
16 distributed generation. I think there might be  
17 some information in our experience in the actual  
18 numbers that now we're paying for.

19 Thank you.

20 MR. TOMASHEFSKY: Thank you, Kevin; and  
21 thanks to all of you for providing your input.  
22 Now we're going to have an opportunity to get some  
23 feedback from folks.

24 Before we start, actually we do have a  
25 little bit of time, so this can work nicely. I

1 just want to remind that we are still in the  
2 process of recording this transcript, so if you do  
3 have a question, I guess what we can do is we can  
4 do it by parade. Commissioner Geesman.

5 PRESIDING MEMBER GEESMAN: Let's do it  
6 by rank.

7 MR. TOMASHEFSKY: We'll start with you.  
8 But let me do the logistics first.

9 PRESIDING MEMBER GEESMAN: Thank you.

10 MR. TOMASHEFSKY: If you don't mind.  
11 So, and of course, you have your microphone there,  
12 so you don't have to go anywhere.

13 But when we do get to that point we'll  
14 just go down and you could form some sort of  
15 collegial line and ask your questions. Make sure  
16 you do state your name and affiliation again, and  
17 please drop off a business card to our court  
18 reporter.

19 And with that, I offer you the mike.

20 PRESIDING MEMBER GEESMAN: I only had  
21 one question, actually. I want to thank all of  
22 the panelists for your presentations. I've read  
23 many of your papers previously and I think that  
24 they're very helpful to the development of this  
25 record. I think they'll be helpful to the PUC.

1 And I know they're helpful to the Energy  
2 Commission in trying to chart our course.

3 I had a question for Carl. As you may  
4 know in our 2003 Integrated Energy Policy Report  
5 the Energy Commission embraced the recommendation  
6 that we attempt to bring more transparency to the  
7 distribution planning process.

8 And I was intrigued to learn more about  
9 your thoughts. And I'd invite the other  
10 utilities, as well, to address this question in  
11 any written comments you file. How you think the  
12 regulatory system can better provide transparency  
13 in that distribution planning process, and how can  
14 we better assure that distributed generation is  
15 considered an apples-to-apples option by  
16 distribution planners?

17 I'm a little bit wary of this, having  
18 gone through the process in the '70s where, for I  
19 would estimate a good ten years, we flogged the  
20 issue of trying to make demand side measures an  
21 equal status option in generation planning. I  
22 think we made some progress in that area after  
23 about ten or perhaps a little bit longer years of  
24 flogging.

25 I wonder if we couldn't jump-start this

1 process as it relates to distributed generation in  
2 planning for the distribution system.

3 MR. SILSBEE: As an economist it's  
4 difficult for me to get into the issue of  
5 transparency with regard to what the engineers do  
6 in evaluating T&D systems. I find the issue  
7 somewhat arcane, difficult even though I did have  
8 an undergraduate engineering degree.

9 The soapbox I always get on is one of  
10 focus on incentives to do the right thing. I  
11 think there's two elements of that. One is making  
12 sure that the ratemaking process puts the utility  
13 in a situation where they're enabled to do what's  
14 right. In that regard I worry about  
15 micromanagement which I think sometimes is  
16 counterproductive.

17 And the other thing is a free flow of  
18 information. I don't think there's any question  
19 but that the focus that the Commissions have had  
20 on DG has caused utilities to look more carefully  
21 at the opportunities. And I think that's  
22 something that's important.

23 At the same time I worry very much about  
24 attempts to be prescriptive about the direction  
25 that's given by the Commissions. I think it's

1 important to create an incentive structure that  
2 enables the utilities and customers to do the  
3 right thing with regard to DG; but to ultimately  
4 let the choices be made by those who are in the  
5 front ranks, so to speak, and empowered with the  
6 responsibility to make such choices.

7 PRESIDING MEMBER GEESMAN: Thank you.

8 MR. TOMASHEFSKY: I'd be curious to open  
9 that up to the rest of the other panel members,  
10 actually, for a brief response to that, as well.  
11 Maybe we could start with you, Joe, and just work  
12 across the table.

13 MR. IANNUCCI: Well, I get to be on the  
14 hot seat, too, huh? It's a very good question,  
15 Commissioner. I think it opens up a whole range  
16 of issues as to whether the tools that the  
17 ratemakers can use to give the proper price  
18 signals to distributed resources are really  
19 orthogonal to the ones you'd really like to be  
20 able to use for distributed resources in general.

21 I think about things such as customer  
22 class distinctions versus locational distinctions.  
23 And while I would love to see transparency in the  
24 distribution planning systems avoided costs,  
25 publishing some kind of a book that said where the

1 hot spots were and what they cost, it's hard for  
2 me to exactly see how you could do that and not  
3 have some trouble with cross-subsidization between  
4 customer classes.

5 So I'll just bite off that tiny little  
6 piece of the problem and respond to that.

7 MR. MARNAY: Yeah, I think we've got too  
8 many economists on this panel --

9 (Laughter.)

10 MR. MARNAY: -- and a third economist to  
11 be named later, so I find myself in agreement with  
12 the rest of the panel. I pretty much agree with  
13 what Carl said, that the key is just to create an  
14 environment and incentives in which people really  
15 do want to do the right thing, and are rewarded  
16 for doing the right thing.

17 And, of course, as an economist what  
18 that means, one thing above all else, which is to  
19 just get the prices to look right. If the  
20 customer sees something related to the true costs,  
21 then from a societal point of view he or she is  
22 likely to respond accordingly.

23 And then just to underscore what Joe  
24 said, I mean that's no trivial matter.  
25 Particularly when you're talking about costs that

1 are not only differentiated over time, which we're  
2 fairly familiar with in the utility business,  
3 although we haven't had a great amount of success  
4 at delivering time differentiated prices to  
5 customers in general, we certainly recognize the  
6 importance of it.

7 Here we're worried about spatially  
8 differentiated prices, as well, which is pretty  
9 complex and really gets to some very sensitive  
10 political issues that I think Joe alluded to.

11 I mean no utility wants to release a  
12 book that says my distribution system is weak in  
13 this area. It's pretty unlikely. So, not to  
14 undersell the difficulty of doing it, but  
15 nonetheless I think top priority should be trying  
16 to deliver the right incentives.

17 MR. DUGGAN: I really can't add a lot to  
18 what's been said. Price signals are important, I  
19 agree. I guess all economists speak the same in  
20 some respects.

21 I think, though, that this proceeding is  
22 going to be very useful in terms of understanding  
23 how you would structure the price to give the  
24 right signal. If it finds and agrees on what  
25 benefits are delivered, and I think that's a big

1 challenge in itself, just to identify and  
2 determine what benefits are provided by  
3 distributed generation. We know the benefits, we  
4 can start to look at the technical matter of  
5 pricing or valuing those benefits. And then  
6 reflect those values in the rates.

7 MR. PRICE: One last perspective on  
8 this, and my perspective has come, really, from  
9 trying to do some of this in New York. And I'm  
10 going to be talking a little bit this afternoon  
11 about what we found in the T&D process and trying  
12 to do that.

13 And in my presentation this afternoon I  
14 think what I've tried to do is set up sort of what  
15 DG has to do in order to get this transmission and  
16 distribution capacity value that we've added. You  
17 know, Joe mentioned that pretty much every study  
18 has talked about having that piece in there, the  
19 transmission capacity piece, the distribution  
20 capacity piece.

21 And I think there is value there, but I  
22 think there's also value in making it very clear  
23 exactly kind of what it is we're asking DG to do,  
24 and be sort of as clear as possible to those  
25 putting together DG projects, on sort of what that

1 looks like.

2 And I can talk, at least in New York,  
3 about how that came out in terms of well, what are  
4 the requirements really for DG in order to capture  
5 some of that distribution value.

6 MR. IANNUCCI: Just following up on that  
7 if I might, also we need to say what we're not  
8 asking the distributed resource to do, for those  
9 type of applications. For instance, those are  
10 really capacity applications in the distribution  
11 system. As you show, you only have to operate a  
12 few hours, so you wouldn't necessarily try and  
13 make that an energy resource. We shouldn't  
14 confuse those two.

15 MR. TOMASHEFSKY: Good, thank you. Any  
16 followup at all? Great. How about let's start  
17 off with a show of hands of who wants to ask a  
18 question. We can go from there. Steven, do you  
19 want to start off?

20 MR. GREENBERG: Good afternoon and thank  
21 you, panelists and Commission, my name is Steven  
22 Greenberg; I'm with Distributed Energy Strategies.  
23 We're an energy consulting firm representing some  
24 of the folks in the room here today and ourselves.

25 The question I have mostly goes to the

1 comment by Carl on distortions and wanting to  
2 see -- not wanting to see rates that distort the  
3 signals. I think it's been talked about there's a  
4 number of distortions that are already existent.  
5 Customer class cross-subsidies exist. And  
6 locational subsidies currently exist.

7 But I think perhaps as far as DG and  
8 demand side measures go, specifically the biggest  
9 distortion that you see now is monthly ratcheted  
10 demand charges. And when so much of the economic  
11 benefit of a DG unit or demand side management  
12 measure can be lost in, you know, less than -- now  
13 you're talking seven 9s, because in 15 minutes out  
14 of the 720 hour month you can lose, you know, 50  
15 or 60 percent of the benefit.

16 I'd ask the panel, actually, and most  
17 specifically Carl, and any other utilities, what  
18 movement do you see towards moving towards either  
19 a daily demand charge or rolling average. And,  
20 you know, there is other precedent for that. New  
21 York has gone to daily demand charges with ConEd.  
22 Pasadena does a rolling average.

23 So that's the question I have.

24 MR. SILSBEE: Unfortunately I'm going to  
25 take a contrarian position on that. The studies

1       that I've done indicate that about half the costs  
2       in the delivery grid are infrastructure-related.  
3       They tie to the geography of the grid, not to the  
4       customer usage at individual sites within that  
5       grid.

6               The analogy would be the street that  
7       connects your house to a major highway. The  
8       street is sized not based on the volume of use,  
9       but just to provide you access to your commuting  
10      route to work or wherever you go to enjoy your  
11      weekends.

12             It's the same thing with regard to  
13      distribution. Poles don't vary with the number of  
14      electrons that are carried on the wires.  
15      Underground conduits don't, either. To a large  
16      degree these are a function of geographic density  
17      in the area.

18             Rate design specialists, of which I'm  
19      not one, use a variety of different techniques,  
20      including demand ratchets, as a way to get  
21      recovery of some of those fixed infrastructure  
22      costs of the delivery grid. Because predominately  
23      delivery costs are recovered in energy and demand  
24      charges. And, thus, when somebody reduces their  
25      usage on the system they continue to have the

1 benefit of access, but aren't paying the full cost  
2 of that connection.

3 MR. TOMASHEFSKY: We can start from  
4 Snuller's side. Do you have a comment you want to  
5 add to that? You don't have to. Anybody else?  
6 Joe.

7 MR. IANNUCCI: When I showed the results  
8 for the Detroit Edison analysis and I alluded to  
9 the very interesting case of the joint  
10 optimization, it was exactly that demand ratchet  
11 issue that we released, that constraint. And that  
12 really made a huge difference. That was the  
13 biggest difference that we could make in the  
14 market at that point, was to take those demand  
15 charges and spread them out over the hours that  
16 the utility really cared about that, and put in a  
17 huge penalty if the distributed resources didn't  
18 work during those hours, \$1, \$1.50 a kWh during  
19 those hours.

20 And when you looked at that in a more  
21 holistic way, the market -- the air cleared; you  
22 could see what was going on. The demand was cut  
23 back.

24 Now, I'm not going to disagree with my  
25 friend from SCE in terms of embedded investments

1 in the distribution system. But when you get to  
2 the point when you need an upgrade, or you think  
3 you might need an upgrade, this just comes right  
4 to the fore.

5 MR. TOMASHEFSKY: And I suspect when  
6 we're done with a lot of this work here that will  
7 feed into the second portion dealing with the  
8 cost/benefit work that goes on with this  
9 proceeding. So, a lot more to come on that  
10 particular issue.

11 Any next questions?

12 MR. HANSEN: My name is Doug Hansen from  
13 San Diego Gas and Electric. And my question goes  
14 to Mr. Price, page 13, or slide 13.

15 I see in that slide it appears to be a  
16 representation of PG&E's specific climate zone, or  
17 a specific climate zone. And having looked at  
18 SDG&E's some 900 circuits and when we are peaking,  
19 and that we are fairly much a single climate zone,  
20 I've noticed that our distribution circuits tend  
21 to peak anywhere from 6:00 a.m. to about 10:00  
22 p.m. And there's a huge diversity of that by  
23 circuit. There is no singularity or concentration  
24 that appears like the concentration I see in your  
25 slide.

1 I was hoping you could help me  
2 understand what this representation is of. Is  
3 PG&E really that homogenous on its circuits? Or  
4 is there something else going on here?

5 MR. PRICE: The level of disaggregation  
6 here, a lot has to do with sort of how far up the  
7 system you get from the customer. If you are  
8 right down on the customer and the most finest  
9 level at a street address, you might find the peak  
10 could occur at anytime. They decide to run their  
11 hair dryer, they got a peak load.

12 As you go up the system to a feeder  
13 level, you might get some diversity, and you might  
14 get some smoothing.

15 If you go up to substation level more,  
16 distribution planning level more, and what this  
17 picture is of here is out to the entire San Jose  
18 kind of planning division for PG&E. Now, that is  
19 a pretty remarkable disaggregation if you think  
20 before we had statewide average avoided costs. So  
21 we've gone down to a PG&E planning division.

22 I believe that the SDG&E's whole avoided  
23 costs for this efficiency is the entire SDG&E  
24 service territory.

25 Now, the T&D avoided costs here are

1 really average. As you know, you'll find areas on  
2 your distribution system where there is no  
3 capacity value because there's plenty of capacity.  
4 And there are other areas that have, you know,  
5 that may have projected capacity upgrades.

6 And so what we're seeing here is an  
7 average; it's not the extreme high; it's not the  
8 zero; it's if you did efficiency in this sort of  
9 planning division, on average what would that cost  
10 look like. And then it's allocated based on a  
11 shape that looks a lot like the loads -- should be  
12 as representative as we can on the loads for that  
13 circle.

14 So that's, you know, there are  
15 admittedly some simplifications for this in order  
16 to make it implementable for, you know, the  
17 efficiency program evaluations. And, you know, I  
18 guess taking a broader context back for DG, what  
19 we're talking about is DG on a specific point.

20 So it's appropriate to use -- and I'm  
21 not here to necessarily answer what's appropriate  
22 for the DG piece at all, but is it appropriate to  
23 use sort of the average for down to a planning  
24 division for a specific point. You know, some may  
25 look just like the average and some may not.

1 MR. HANSEN: Thank you.

2 MR. SILSBEE: If I could add to that,  
3 Doug, we have a similar concern with the  
4 application of an averaged avoided T&D factor  
5 across our service area, as well. I think we  
6 probably have very similar phenomena with  
7 different circuits peaking at different times.

8 I would note that the E3 study  
9 recommends that for specific applications there be  
10 allowed an adjustment downward to diminish the  
11 impact of the T&D avoided cost multipliers.

12 I'd like to hang onto that. I think  
13 that's very important. The E3 study was intended  
14 for DSM applications originally. And there's  
15 certainly a lot of talk about extending its  
16 application elsewhere.

17 But I think it's very critical to  
18 recognize that the T&D avoided cost values may not  
19 apply to an individual DG installation in a  
20 particular location. It's going to be very site-  
21 specific.

22 PRESIDING MEMBER GEESMAN: How would you  
23 address it from a utility planning standpoint,  
24 though? I mean take the utility's perspective.  
25 Is a circuit-by-circuit vantage point a more

1 accurate reflection of the way you think the costs  
2 and benefits of any DG investment to the utility  
3 should be valued?

4 MR. SILSBEE: Well, my understanding is  
5 that in our distribution planning process we're  
6 now explicitly including DG as an option, looking  
7 at the cost effectiveness of a DG type of  
8 application along with various ways that we might  
9 solve a local problem in terms of distribution  
10 upgrades.

11 PRESIDING MEMBER GEESMAN: But do you  
12 know how granular you get in that evaluation? Do  
13 you go by planning area or by distribution  
14 circuit-by-circuit-by-circuit?

15 MR. SILSBEE: My understanding is it  
16 gets down in some cases even below the level of an  
17 individual circuit to segments of circuits.

18 One thing that we do in some areas is we  
19 see differences in demand from summer to winter.  
20 So we may take a segment of a circuit and switch  
21 it from one feed to a different feed to balance  
22 usage. This is done by monitoring loads on  
23 individual transformers in the system.

24 So, it's very very micro in orientation  
25 at times.

1               PRESIDING MEMBER GEESMAN: And is it a  
2       standardized approach? I mean do you follow a  
3       consistent protocol as to when to disaggregate it  
4       to segments of a circuit? Or is it more  
5       judgmental?

6               MR. SILSBEE: Well, what is defined,  
7       you're way beyond the area that I know --

8               PRESIDING MEMBER GEESMAN: Okay.

9               MR. SILSBEE: -- intimately. But, you  
10      know, there are practices that we follow when  
11      circuits or transformers start to get overloaded  
12      and we believe that there's some accommodation we  
13      need to make to continue to provide service within  
14      the adequate parameters.

15              At that point people will look at  
16      different solutions. One solution might be the  
17      circuit switching. Another would be to fill in a  
18      new distribution circuit to take demand off the  
19      existing circuits. Another option in that  
20      circumstance that we'll consider would be putting  
21      a DG unit in.

22              PRESIDING MEMBER GEESMAN: Thank you.

23              MR. TOMASHEFSKY: Joe.

24              MR. IANNUCCI: Can I give three very  
25      quick followups. Number one, in our work with the

1 utilities around the United States we get exactly  
2 the same shape of curve that Snuller was showing.  
3 So I'll confirm that that's correct as far as I  
4 can tell from my few years in this business.

5 Number two, I think the real point is  
6 that that's not a flat surface. The real point is  
7 that there is a peak. Whether it's in the morning  
8 or the afternoon it interesting and very useful  
9 for actually how you dispatch the distributed  
10 resources.

11 The point is you would put in a  
12 distributed resources if it made sense, and turn  
13 it on whenever that peak was, if you were told  
14 when the peak were.

15 And number three, I agree we need to go  
16 more grainy on this. If we are going to be more  
17 transparent, and now I'm getting back to the  
18 Commissioner's first question, then in fact we  
19 need to have this very same data on a feeder-by-  
20 feeder basis. I don't know that I'd go any finer  
21 than that, but that exactly would tell you then  
22 where to put in distributed resources and how much  
23 you'd have to operate them.

24 MR. TOMASHEFSKY: Thank you. Kevin.

25 MR. BEST: Thank you, Scott. I had a

1 question for Snuller. Kevin Best, RealEnergy.

2 Snuller, as you know, of our two dozen  
3 plants, most of them are combined heat and power,  
4 and most of them we run chilled water absorption  
5 systems with our waste heat. So my question  
6 coincidentally is on this exact same slide.

7 Should we have these values that we see for  
8 straight DG that's just not running in combined  
9 heat and power mode, not recycling their energy?  
10 Or should we double these values for those plants  
11 that are also offsetting electric --

12 MR. PRICE: Yeah, --

13 MR. BEST: -- throughput from running  
14 chilled water systems.

15 MR. PRICE: Right. And I think this  
16 gets to a really important point that I think Joe  
17 brought up earlier, and others have, as well,  
18 which is perspective. And sort of whose benefits  
19 are we looking at here. Because I think a lot of  
20 what to do with the sort of the, you know, the  
21 chilled water use or the waste heat recovery  
22 values occur to the customer that was really below  
23 the radar of any of this estimate here for  
24 efficiency.

25 You know, this was basically for those

1 used to the terminology, this is the sort of  
2 social cost test for efficiency. That's why we've  
3 got environmental externality in there, and those  
4 components.

5 If the customer is getting waste heat  
6 recovery in addition, then that's an additional  
7 benefit that wouldn't be on that picture.

8 MR. BEST: Very good.

9 MR. PRICE: Yeah. There, from a  
10 financial perspective, might be things on there  
11 such as the, you know, the value of cleaner air  
12 and fewer greenhouse gases that may not, you know,  
13 financially accrue to any of our stakeholders,  
14 either. Although, for efficiency evaluation, that  
15 was put in there. For efficiency, yeah.

16 MR. BEST: Very good. So this does not  
17 include recycling the energy for either boiler  
18 offset or for chilled water offset?

19 MR. PRICE: No.

20 MR. BEST: Okay. Thank you.

21 MR. TOMASHEFSKY: Any other takers?

22 DR. McCANN: I'm Richard McCann with  
23 M.CUBED. I wanted to follow up with two comments.  
24 The first one following Commissioner Geesman's  
25 question about distributed investment decisions.

1           We've been an intervenor in several  
2   general ratecases at the PUC. And one of the  
3   things that we've always run into is the  
4   opaqueness of distribution investment and try to  
5   decipher the data that is handed down from the  
6   utilities as to how they are doing their  
7   distributions. You'll look at certain areas and  
8   there will be significant excess capacity in one  
9   location and actually deficits in other locations.  
10   And the explanations for why those things have  
11   occurred are always couched in terms which are  
12   difficult to decipher.

13           And listening to this discussion it  
14   makes me think that perhaps one of the most useful  
15   functions that we could have in this proceeding is  
16   actually have a workshop with distribution  
17   engineers, basically describing how each one of  
18   the utilities makes their decisions about how to  
19   invest in distribution expansion in particular  
20   locations. Because that has always been somewhat  
21   of a mystery in the general ratecases. And I  
22   think that just having that explanation so that we  
23   could decipher that information would go a long  
24   ways towards answering a number of these  
25   questions.

1           PRESIDING MEMBER GEESMAN: I think  
2           that's a terrific idea. And we will follow up and  
3           figure out a way in which to do that.

4           DR. McCANN: The second one was a  
5           followup on a comment that Mr. Duggan made about  
6           the difference in time horizons between DG  
7           investments and T&D or generation investments.  
8           And one of the things that's not on the list of  
9           benefits that I saw that was put up was basically  
10          what I would call the value of information.

11          That is the ability to defer your  
12          investment decision until closer to the point at  
13          which the investment is going to occur. And you  
14          can actually place a value on that based on using  
15          financial instruments or something along those  
16          lines. So it's actually something that can be  
17          relatively easily quantified using financial  
18          analysis. And I think it's one of the things that  
19          should be on the list in comparison of DG versus  
20          T&D investments.

21          Thanks a lot.

22          MR. TOMASHEFSKY: Joe, you want to  
23          respond to it?

24          MR. IANNUCCI: That one is fun, that is  
25          really fun because those are actually the same

1 things, those are two sides of the same coin. If  
2 you look at how a distribution planner really  
3 plans, what they're trying to do is to manage  
4 risk. They may not know it, but they manage risk  
5 every time they make a decision.

6 And so that's really kind of the same  
7 thing looked at from two different standpoints.  
8 The value of modularity and portability and such.  
9 And that will be a sleeping giant. I think  
10 there'll be some very interesting research coming  
11 out soon on modularity and portability, and how  
12 that plays against the risk that a distribution  
13 planner has to live with.

14 MR. MARNAY: Can I add a couple points?

15 MR. TOMASHEFSKY: You sure can.

16 MR. MARNAY: Yeah, I completely agree on  
17 the options value part of it that that's exactly  
18 right. I mean the longer you wait the more  
19 options that you have. And that's actually worth  
20 something. And there are actually ways to  
21 calculate that.

22 Just to come back to a point that Joe  
23 made earlier about upgrades. It's when the  
24 upgrade is due that things become important here.  
25 I'll just make two comments on that.

1           Number one, an idea that we've kicked  
2           around although we've never really tried to flesh  
3           it out at all is it would be much more rationale  
4           ratemaking if you started to pay for those  
5           upgrades ahead of time. Because after the upgrade  
6           is made and there's excess capacity, well, you  
7           really don't need the DG anymore.

8           So one of the fundamental problems with  
9           ratebased regulation is we only worry about this  
10          and we only pay for it after the fact. I think  
11          that's something to think about.

12          Second point is in terms of the  
13          upgrades, the distribution system unfortunately  
14          has a lot of flexibility in it. So it's not  
15          exactly predictable when an upgrade is going to be  
16          necessary. I mean hypothetically people imagine  
17          an isolated feeder, and you know when the  
18          substation needs to be upgraded and the conductors  
19          and so on. But the reality of urban areas isn't  
20          really like that.

21          And, in fact, wherever you live you  
22          might be served on several different feeders. And  
23          in fact, distribution engineers are reconfiguring  
24          the system all the time.

25          So even though you might imagine

1 hypothetically that there's some physical,  
2 tangible, measurable upgrade out there in the  
3 future, that really isn't always that simple. And  
4 in fact, a whole lot of things can change between  
5 now and an actual physical upgrade really being  
6 made.

7 MR. TOMASHEFSKY: Any other comments  
8 along the table? Stephen.

9 MR. TORRES: Good afternoon. My name is  
10 Stephen Torres; I work for FuelCell Energy, and  
11 also represent the California Coalition of Fuel  
12 Cell Manufacturers. We basically build stationary  
13 fuel cells for power generation.

14 I have a couple comments that I'd like  
15 to make, one -- one in process with regard to  
16 contents. My observations from this afternoon is  
17 that specific environmental benefits, specifically  
18 those that are delivered by the cleanest of  
19 technologies -- we call those ultraclean  
20 technologies here in California -- have clearly  
21 been identified as being very important, both by  
22 the Legislature as well by previous CPUC  
23 proceedings.

24 However, many of the presentations today  
25 describe the quantification of those benefits as

1       being very difficult or nearly impossible. So I  
2       just want to raise that as an issue of concern, is  
3       that this proceeding somehow needs to address the  
4       disconnect between environmental benefits,  
5       environmental issues that continue to be important  
6       in the State of California and what we've seen so  
7       far as being just a difficulty of quantifying  
8       those benefits.

9               The second comment I have is with regard  
10       to process. And this one I really would like to  
11       start by applauding both Commissions for this  
12       joint efforts. And just to state that -- make the  
13       Commission aware that the difficulty that some  
14       parties are very much affected by this proceeding  
15       will have in participating effectively in  
16       bifurcated, prolonged and parallel proceedings.

17              In other words, we're small project  
18       developers, we're small fuel cell companies, we  
19       have very limited funds and you cannot expect us  
20       to effectively participate in these discussions if  
21       the discussions are very prolonged, bifurcated.

22              So I do want to make you aware of that.  
23       I want to applaud these joint efforts, and I hope  
24       that you continue to take those interests of the  
25       small voices into account as you continue to

1 structure this proceeding going forward.

2 Thank you very much.

3 PRESIDING MEMBER GEESMAN: I think  
4 that's well taken, Stephen.

5 DR. ELY: Thank you, Mr. Commissioner.

6 My name is Richard Ely. I work for Davis Hydro.

7 It's a small, independent hydropower developer. I  
8 have three comments and a process question.

9 I'll do away with the process first.

10 I'd be most grateful if a member of the Commission  
11 Staff would put on a webpage direction to many of  
12 the reports and papers that have been mentioned  
13 here. There doesn't seem to be a sort of a single  
14 point to go to to follow this up, and I think  
15 there's an excellent amount of work; it would save  
16 us all, at least myself, an awful lot of time if  
17 we could have that just administrative thing done.

18 I have three comments in the ways of  
19 question, three sort of question areas. One is to  
20 the general public, which I will close with. And  
21 the other two have to do with the presentations  
22 directly.

23 If I may, Joe, you started very much in  
24 looking at the, from an economist point of view,  
25 since we seem to have a lot of them here, at least

1 two, you focused a lot on the --

2 UNIDENTIFIED SPEAKER: The other ones  
3 couldn't find the room.

4 (Laughter.)

5 DR. ELY: You focused on the savings, if  
6 you will, the technical savings and the technical  
7 benefits. And many of your reports that you cited  
8 were on, in effect as the economist would look at  
9 it, a shift in the supply curve of various  
10 features of distributed generation.

11 Whereas, Chris, you went on and noticed  
12 that there were market effects a little bit over  
13 on the price side, price stability you mentioned,  
14 I believe. And you mentioned markets.

15 One of the things that I would like to  
16 point out is that the ISO has gone to location  
17 zone pricing. And sees very much that pricing is  
18 a highly local, a buss level, they'd like to get  
19 it as fine grain as possible. I think that's very  
20 important. And when we look at these kinds of  
21 things, what's happening currently in the market  
22 is that there are an enormous amount of market  
23 failures at these local markets. As you go to  
24 finer and finer grain markets you increase the  
25 number of market failures that can take place.

1           In effect, if you go to zone pricing you  
2 go to zone market failure. If you go to buss  
3 pricing, you go to buss market failure.

4           There is a terrific opportunity  
5 therefore in terms of market structure by  
6 introducing injecting distributed generation, in  
7 effect, on those busses. The effect of  
8 stabilizing the market is not in the gross sense  
9 in terms of total prices or aggregate prices, but  
10 rather it's very much down on the aggregate of all  
11 the individual markets which are now buss level  
12 markets.

13           That could be looked at from an  
14 economist point of view by looking at  
15 differentiation of marginal and average costs as  
16 seen on these local ISO busses. And I encourage,  
17 or if I may suggest or question whether or not  
18 studies might go through market observation  
19 looking at market performance, back to the market  
20 structure. I think that would give an awful lot  
21 of impetus as to why we, as a society, should look  
22 at those price signals to give clues where we  
23 could do better in terms of how to form the  
24 markets.

25           Those signals, I do not mean in any way

1       that the -- I don't mean to suggest, even though  
2       it may be happening, that the utility companies  
3       are taking advantage or any of the marketers are  
4       taking advantage of these individual buss level  
5       markets. Of course they are. Of course everybody  
6       is. Of course if I were a distributed generator,  
7       so would I. And that's what's good about them.

8               They are, unfortunately, in a regulated  
9       environment and can use these signals for knowing  
10      when to increase, to inject, to allow to change  
11      the system.

12             So, one of my questions, Chris, is could  
13      we or are there studies that look at the market  
14      structure and market pricing type things. I'd be  
15      grateful if you could address that.

16             And let me close by changing the subject  
17      slightly. I'll sit down and then listen to the  
18      responses. One of the background things here  
19      that's been mentioned a couple of times, and that  
20      is the idea that there's sort of a, we want the  
21      ISO, or we want to be able to turn on distributed  
22      generation.

23             Well, the beautiful thing about  
24      distributed generation, if given price signals, it  
25      will turn on itself. And we haven't really sort

1 of mentioned here the infrastructure needed to  
2 effect a distributed generation market. It isn't  
3 much. It's basically an ISO type structure, but  
4 instead of the ISO pulling the strings, it, in  
5 fact, is letting all the distributed generators  
6 pull the strings that causes stability.

7 That's very much something that the  
8 Commission or that could be looked into because  
9 frankly it's so cheap. Information is cheap. And  
10 we're moving into the information age. And that  
11 information, as well as the information we see in  
12 the ISO zone prices, gives signals as to exactly  
13 how and where and when distribution system, nodes,  
14 busses, feeders can be upgraded.

15 And my final comment or question, and  
16 this is really to the Commission, is one of the  
17 ways -- and this is the vision thing, and I  
18 haven't really heard the vision thing here, so I  
19 thought I'd throw one out so we could all laugh a  
20 little bit -- but right now we see the ISO, or the  
21 ISO certainly sees itself as the ultimate director  
22 of where power flows, when and why and what.

23 One of the things that the economist  
24 likes to think of is to do away with the ISO. In  
25 effect have the price, have the market so

1 efficient, the information so plentiful, that, in  
2 fact, there is no central commissar of power.  
3 There is no ISO.

4 I'd be most grateful for your comments.  
5 Thank you, Mr. Commissioner.

6 MR. MARNAY: So just when I thought I  
7 was going to escape this without having to be  
8 confronted by a direct question, so thanks, Rich.  
9 The question turns out to be longer than my talk,  
10 so --

11 (Laughter.)

12 MR. TOMASHEFSKY: Chris, just as a  
13 cautionary note, we have about two minutes.

14 MR. MARNAY: Oh, great, I'm saved by the  
15 bell.

16 MR. TOMASHEFSKY: So if you can say it  
17 in '78 speed that'd be great.

18 MR. MARNAY: So let me make a couple of  
19 quick comments. Number one is yes, the definition  
20 of locational marginal price is the generation  
21 cost plus the losses plus the congestion. And  
22 that congestion number, you know, is exactly what  
23 we're interested in. And to the extent that we  
24 have LMP, yes, that's very valuable information to  
25 the end user.

1 I'm much more worried about the fact  
2 that the customer is not really ultimately going  
3 to see that price than that we have a problem with  
4 it.

5 One cautionary note that I would make  
6 about congestion costs. In work that we've done  
7 in New York here's a highly congested market, and  
8 then sort of hypothetically everybody can imagine  
9 that getting power into New York City and Long  
10 Island is very difficult. And, in fact,  
11 congestion creates quite a differential between  
12 the LMPs in those two zones than in the rest of  
13 the nine New York zones.

14 Even though that's true, and even though  
15 that's powerful and would be a powerful incentive  
16 to DG adopters, you have to be aware that  
17 congestion costs are highly variable. Even in  
18 that situation, which is one of the most simple in  
19 terms of the nature and direction of the  
20 congestion, 25 percent of the time the congestion  
21 is outward from Long Island and not inward.

22 And year-to-year, month-to-month, day-  
23 to-day congestion can actually change quite a lot;  
24 and those congestion charges can change a lot.

25 So, in terms of an incentive stream

1       it's, you know, now what the DG developer would  
2       most like to see.

3               And then just one other comment on the  
4       vision thing. Yes, I mean I think you said it  
5       very eloquently there. I mean the ideal system  
6       for me, and obviously for you, is one in which the  
7       incentives get the DG operator to dispatch himself  
8       correctly. And that we really don't need the  
9       tyranny of a central ISO.

10              But I think we're a very long way from  
11       that ideal right now. I mean we can move towards  
12       better incentives and we certainly should.

13              MR. TOMASHEFSKY: Thank you, Chris. You  
14       have about four seconds if you want to add  
15       anything to that.

16              I want to express my appreciation to the  
17       panel. I just want to leave this panel with a  
18       parting thought. If you look at this chart that  
19       Joe put together about -- when he presented it  
20       about an hour and a half ago, the thing I just  
21       want to have people focus on is that this is  
22       something to think about in terms of if you're  
23       going to quantify this stuff we've got to figure  
24       out what gets classified under benefits.

25              We also have to do the similar offset to

1       this, what would be the cost side of this picture,  
2       as well.

3               So, when we look at the matrix we want  
4       to look at the full matrix and whether this is a  
5       net benefit or net cost. I think we just need to  
6       be explicit so that we can actually do something  
7       with it as we move forward. And the quantitative  
8       aspects of that is difficult, as we're going to  
9       find out.

10              If we could just have a quick round of  
11       applause for our panel, we can go on from there.

12              (Applause.)

13              MR. RAWSON: Okay, we're scheduled to  
14       take about a 15-minute break. And reconvene at  
15       3:45 and we'll start the second panel.

16              (Brief recess.)

17              MR. RAWSON: There was three studies  
18       that were during the first panel by Joe Iannucci,  
19       Chris Marnay and the avoided cost study that  
20       Sneller talked about. We actually have links on  
21       the Commission's website for those documents. If  
22       you go to the Energy Commission website and click  
23       on the distributed generation. Over here on the  
24       right-hand side under distributed generation there  
25       is an announcements page. And if you go to

1 reports and presentations it gives you the URL  
2 here for where those documents in today's  
3 presentations are posted.

4 Also, this link is provided at the  
5 bottom of the agenda that we made available at the  
6 beginning of the workshop so you can find the link  
7 to get to the electronic copies of the  
8 presentations and the documents there, as well.

9 Why don't we get started with the second  
10 panel. The second panel is going to focus on some  
11 of the research activities that the Energy  
12 Commission and New York have been involved in over  
13 the last couple of years.

14 And we have Snuller Price is going to  
15 present again. He's doing double duty today,  
16 after teaching a seminar all day yesterday in  
17 Wisconsin. He flew back last night to be here  
18 today for this, so we appreciate his attendance  
19 here.

20 The first presentation is going to be by  
21 Snuller. He's going to talk about three different  
22 projects that he's been involved with that are  
23 looking into how DG can support the distribution  
24 system, and what the quantitative costs and  
25 benefits are to do so.

1           A unique aspect of one of the projects  
2       he's going to talk about is quantifying the  
3       reliability effect of DG.

4           Our second presenter is going to be  
5       Peter Evans from New Power Technologies. Peter's  
6       been working with Silicon Valley Power to develop  
7       an integrated T&D modeling tool that enables the  
8       analysis of DG and demand response impacts and  
9       benefits to be done with much greater granularity  
10      than present day methods are capable of.

11          And our third speaker is Ellen Petrill  
12      from the Electricity Innovation Institute. And  
13      Ellen's going to be discussing national public/  
14      private partnership that PIER's been involved in  
15      that's looking at how to develop business  
16      structures that create wins for ratepayers, DG  
17      customers and utilities, alike.

18          All of this work with the exception of  
19      one of the projects that Snuller is going to  
20      present are projects that are being funded out of  
21      the PIER program. And specifically are being led  
22      under the leadership of Laurie ten Hope and George  
23      Simons, who are the Team Leads of the Energy  
24      Systems Integration and PIER Renewables programs  
25      respectively.

1                   So with that, I'll go ahead and let  
2                   Snuller start us off.

3                   MR. PRICE: Thanks, Mark. What I'm  
4                   going to do is walk through briefly three ongoing  
5                   projects that E3 is involved with in relationship  
6                   to DG. As Mark mentioned, two of them are funded  
7                   by the CEC PIER project; and then the third one is  
8                   a summary of some stuff that we've learned through  
9                   the DG pilot project in New York.

10                  Now, I'm up here talking; just one  
11                  person. But, of course, it's important to realize  
12                  that each of these projects, probably span at  
13                  least 30 people that are directly involved in the  
14                  research if you add up all the utility folks and  
15                  everything else. But I'm going to try to do the  
16                  best I can in terms of summarizing what we've  
17                  learned.

18                  To put this in context, and this is sort  
19                  of how at least I vision DG, and when we talk  
20                  about costs and benefits, in terms of now and with  
21                  DG. And what I've got is a row here for the  
22                  generation piece, a delivery piece, customer  
23                  services and social goals.

24                  What we have now is combined cycle  
25                  plants on the margin. We have combustion turbines

1 on the margin. And we look at DG, at least all  
2 the numbers that I've seen is that energy and  
3 capacity is more expensive in the central  
4 stations, okay.

5 And so when you start to look at the  
6 benefits of DG what that immediately does is makes  
7 you look further down the chain, okay. And we've  
8 got the delivery piece, customer services piece  
9 and social goals.

10 Each of the case studies that I'm  
11 talking about is really focusing on different  
12 aspects of these other pieces. The delivery  
13 piece, what possible value add does DG have there.  
14 On customer services, Kevin was mentioning waste  
15 heat earlier. That's also an additional value add  
16 for DG; reliability, there are other customer  
17 service type benefits and pieces.

18 And then social goals. All right.  
19 Environment, we talked about greenhouse gases and  
20 so on. That's a very possible add if we're  
21 talking about a technology that improves air  
22 emissions. It's also a possible cost if we're  
23 talking about a technology that makes it worse.

24 So, starting with that sort of  
25 generation comparison I think it's important what

1       these case studies to sort of look and try to get  
2       more details as we sort of go down and ask whether  
3       those other pieces, you know, and other DG  
4       benefits really close the gap.

5               My title, Is DG fundamentally better  
6       than our current system. I'm trying to ask that  
7       question in a way that sounds very broad and very  
8       social, okay. Is DG fundamentally a good idea and  
9       is going to have lower costs of energy for  
10      everybody. And hopefully through these case  
11      studies we're starting to get to some of that.

12             The first project I wanted to summarize  
13      is under the PIER renewables program from George  
14      Simons on renewable DG assessment. The R there is  
15      for renewable. So we're really focusing on DG  
16      that's got a big value add there on that  
17      environmental piece we just saw.

18             the project objectives is to develop an  
19      economic and engineering screening methodology for  
20      DG. And we focused on municipal utility  
21      evaluations, okay. So this is a process and a way  
22      for municipal utilities to evaluate renewable DG.  
23      We've included both the economics and the  
24      engineering.

25             The methodology should allow

1 investigators to identify the best locations and  
2 the best timing for DG. So where does it go on  
3 the system. We've really focused a lot on  
4 reliability impacts. When we talked to the four  
5 municipal utilities and sort of their primary  
6 goals with DG, reliability was almost always sort  
7 of the first concept or work that they said. If  
8 they can use DG to improve reliability of their  
9 system then that would be a huge plus.

10 We wanted to get uncertainty. Okay,  
11 we've talked about costs and we've talked about  
12 benefits, but any time you try to unpeel one of  
13 those you end up with a whole range, depending on  
14 where it is, what time, what happens with other  
15 factors. And so we really wanted a methodology  
16 that would kind of encompass and embrace that  
17 uncertainty and give us some information.

18 The key to all this is really not to do  
19 a study. The key to all of this is to identify  
20 potentially successful DG projects. A number of  
21 folks on the panel and in the room, a lot of us,  
22 have done studies of DG and DG economics and so  
23 on. And it's ended at that. And what we really  
24 want to do is focus and try and identify some  
25 successful new DG projects.

1           The four utilities we're working with,  
2       the San Francisco PUC and Hetch Hetchy; the City  
3       of Palo Alto Utilities; Alameda Power and Telecom;  
4       Sacramento Municipal Utility District, are the  
5       four participants. And I wanted to give a brief  
6       overview of how we're doing this.

7           As I mentioned before, we've got  
8       economics and we've got engineering, okay. So  
9       we've tried to put them together. The economics  
10      asks sort of what the cost of benefits look like  
11      of the DG. And the engineering really reinforces  
12      that by asking the question, well, does it really  
13      interconnect to the system in the right place, and  
14      really provide the capacity that we're looking  
15      for. Does it really work. And does it really  
16      work to the distribution engineering folks as part  
17      of their system.

18          So there's a feedback. We've got a set  
19      of benefits. We've got a set of costs of DG. And  
20      we've got an engineering study, and the  
21      engineering kind of feeds back and drives and fine  
22      tunes some of the economics.

23          Our perspective is pretty broad, and I  
24      mentioned perspective a couple times earlier. And  
25      I think the key is really looking for applications

1       that are winners on a couple levels, okay. We  
2       don't want to find just DG that's good for the  
3       customer, but that, you know, results in problems  
4       for nonparticipating customers.

5               The perspectives that we've looked at  
6       are the community perspective, okay. For those  
7       used to doing resource planning, the terminology  
8       total resource cost test might be something that  
9       kind of indicates the concept. But basically are  
10      the total, for example in Alameda, are the total  
11      energy costs in Alameda greater or less with this  
12      DG. That's the perspective.

13             The generator/owner. Does this look  
14      like a financial winner for the DG owner. The  
15      utility customers, okay. What are the impacts on  
16      the utility's rates or operating margin. Or in  
17      the case of a municipal, the amount of money  
18      they're able to contribute to the city fund.

19             If it's a utility-owned project, how  
20      does that look to the utility in terms of their  
21      overall resource portfolio. And finally, the  
22      societal cost test. Remember we're looking at  
23      renewable DG in this project, so we want a broad  
24      social, you know, evaluation of what those  
25      benefits are, and not just kilowatt hours and

1 kilowatts, but also cleaner air, you know,  
2 community-oriented projects.

3           So when we look at the economics from  
4 all these different perspectives we end up with  
5 charts that are not just yes and no. You end up  
6 with a yes, no, yes, yes, kind of analysis.

7           And I just show this chart. It's just  
8 one quick example of one type of technology. This  
9 was a biodiesel generator. And green is the  
10 benefits after you add up all the different  
11 components, the benefits we're looking at. The  
12 gray is that gap that goes to, and the sum is the  
13 total cost, okay.

14           So, in this example, the generation  
15 owner was fine, okay. This was economic to them.  
16 But from the rim test, in other words the  
17 nonparticipants, this was not fine. There were  
18 greater costs than benefits.

19           By doing this analysis for multi-  
20 stakeholders what we're hoping to do is identify  
21 areas and better understanding of why projects are  
22 happening and why they're not.

23           I mentioned the sort of social  
24 perspective. We've spent a lot of time in this  
25 project trying to look at the soft benefits. And

1 the way that's kind of coming out is basically a  
2 decision-tree type of look, where you start with  
3 what type of technology you've got, and then you  
4 trace through, with a group, in terms of, you  
5 know, what benefits that this project might have,  
6 okay.

7 And so what we're trying to do is put  
8 some structure to the laundry list of all these  
9 sort of intangible good things about renewable DG.  
10 And to the extent those are useful to the utility  
11 making the case for these projects within their  
12 city board, remember we're trying to find projects  
13 that are really winners, if those are helpful in  
14 their case for getting the new DG online, then  
15 they're quite useful.

16 On the engineering side what we've got  
17 for each of those utilities is a pretty detailed  
18 circuit model for the entire utility, okay. And  
19 if the way the engineering works is not with a  
20 typical sort of load flow approach where you would  
21 look at just the peak load on the utility system,  
22 what we do is we are able to do a load flow for  
23 the whole system, all the points and all the hours  
24 of the year.

25 And so what that starts to get us is,

1 given a dispatch pattern of DG located at a  
2 specific point on their system, you can start to  
3 quantify things like what are the losses and  
4 what's loss improvement; what's the capacity,  
5 what's the capacity improvement; and reliability  
6 and reliability improvement.

7           You can ask interesting questions like  
8 if I was going to put 100 kW generators on my  
9 system where would I put them. And this is a  
10 schematic of Alameda. For those who have been  
11 there, Alameda has sort of got its main island and  
12 then there's Bay Farm Island down here, and  
13 Oakland Airport somewhere just south of the screen  
14 there.

15           And if you ask that, where is it best to  
16 put DG, you get areas that show up in red as  
17 having the highest value in terms of improving, in  
18 this case, losses. But you could also ask the  
19 same question in terms of capacity. The  
20 difference, of course, being losses accrue over  
21 the whole year, and capacity is just those, you  
22 know, peaks on those feeders.

23           Or you could turn the question around  
24 and say, well, where is DG going to have the least  
25 help, least benefit to my system. Okay.

1           Reliability. Mark asked me to really,  
2       to focus on reliability a bit. And we've taken a  
3       look at this in three different ways. We've done  
4       it every way that we could think of, and I think  
5       different applications lend themselves to  
6       different ways of valuing reliability improvements  
7       due to DG.

8           One is what would often be called a  
9       value of service approach. So, estimating what  
10      the value is to a customer if they don't go out.  
11      And then evaluating, well, how often, in terms of  
12      an expected value, how much less often are  
13      customers going to go out.

14           That works well if you've got areas that  
15      have real imminent and highly likely outages. But  
16      all the four service territories that we've looked  
17      at really don't have a big reliability issue under  
18      that type of thing. They're all well within their  
19      single contingency. Planning criteria for  
20      engineers, there's no imminent capacity projects,  
21      a lot to do with the economy being where it is.  
22      And loads haven't even come up to where they were,  
23      maybe three or four years ago.

24           The second piece sort of establishes the  
25      second approach to this. It's looking at, well,

1       if I establish a benchmark of what the reliability  
2       is on my system right now, and then I put in DG,  
3       how long is the reliability better, until I get  
4       back to where I'm at now. And we've set up a  
5       method that will do that.

6               And here are some results. Again, this  
7       is sort of a stylized piece. We have a metric for  
8       expected overloads or energy exceeding the normal  
9       ratings. And we can compute this with that load  
10      flow model I was showing a graphic of earlier.

11             And what you can do is on this basecase  
12      you can run the existing utility system out. And  
13      that's that top line. And then you can do cases  
14      where, okay, I've got a specific amount of DG  
15      located at a specific location with a specific  
16      dispatch pattern. And I can recompute that metric  
17      in terms of, you know, probability and expected  
18      overloads.

19             And I can look at all right, if my  
20      utility load is 74 megawatts or so for Alameda,  
21      and I put on this case, which are 16 500 kW  
22      generators. And remember, I'm getting pretty  
23      specific here, then my reliability improves; my  
24      expected numbers of outages go down.

25             And then as load grows over time, the

1 peak load of the utility grows over time, I kind  
2 of get back to where I was.

3 This tells us that we have basically an  
4 equivalent of 6 megawatts of load growth for the  
5 peak load with the same reliability. In other  
6 words, the utility's load can grow by 6 megawatts.  
7 We have the same reliability we used to have. And  
8 this has been the most useful metric that we've  
9 found in terms of valuing reliability.

10 Talk about uncertainty analysis.  
11 There's all kinds of ranges of all of these inputs  
12 in terms of benefits. Those that we've really had  
13 a focus on are wholesale energy costs,  
14 transmission costs, or what's going to happen with  
15 the change to more of a nodal LMP pricing system.  
16 Distribution avoided costs and our capital costs  
17 for renewable DG technologies. Everybody in the  
18 room knows those are pretty expensive, so one of  
19 the key drivers is is what they'll ultimately  
20 cost.

21 We think that the value of doing the  
22 sensitivity analysis is it sort of tells you how  
23 robust your answer is. If, and on this chart what  
24 I've got is one of the outputs of our methodology  
25 on the economic side, where you look at changes in

1 your cost inputs. And here I've got them as a  
2 percentage of the total energy value, and the  
3 change in the net benefit.

4 So across your whole range of potential  
5 benefits, nothing flips the answer for your  
6 particular perspective, then you know you've got a  
7 pretty robust solution. And that's the case with  
8 this biodiesel example we've been doing.

9 If you've got the case where, for  
10 example, the transmission costs turn out to be  
11 even much higher that might flip the answer, and  
12 local DG would just have that much more value.

13 I'm going to go through a quick summary  
14 of three here, so I'm going to switch gears a  
15 little bit and talk about a project again funded  
16 by the CEC PIER program, but this is under Laurie  
17 ten Hope and the PIER strategy group.

18 And what we've tried to do here in San  
19 Francisco is look at distributed energy resources  
20 as a test bed site, okay. So now we've left the  
21 land of just purely study, and what we're trying  
22 to look at is real DG applications connected to  
23 real systems.

24 When we look at the literature on this  
25 and the cost and benefits of DG there's not a

1 whole lot out there on actual installations. So  
2 we think this project fits very well in this  
3 portfolio of research on actual applications. The  
4 idea is to identify and verify economic and  
5 engineering interactions or impact, DER on San  
6 Francisco's system.

7 We want to take advantage, we're sort of  
8 taking advantage of those DG units that are  
9 already there or are planned to go in, so that we  
10 can study them. We're not building new DG under  
11 this project, we're just taking advantage of those  
12 that are going in and using them for this  
13 research.

14 We're doing our utmost to pursue a fair  
15 assessment of DER and grid interactions. As you  
16 can imagine, we've got a lot of stakeholders. I'm  
17 going to skip up a slide here. On this we've got  
18 the CEC's funding this; PG&E, who's been providing  
19 distribution system information to this; we've got  
20 San Francisco PUC, Hetch Hetchy, which is the  
21 City's group that's actually planning some new  
22 distributed generation; we've got private DER  
23 owners; we've got technology vendors.

24 So, we're pretty excited that we've been  
25 able to put together a pretty big collaborative to

1 look at this research and do research on real DG.

2 In terms of the project plan, we've got  
3 three phases, and we're just really in the  
4 beginning of phase one. Phase one is economic  
5 analysis and marketing plan development.

6 Basically right now we're trying to put  
7 together the best possible research package that  
8 we can. We made some pretty good strides in that,  
9 and provided we can put together a good plan at  
10 the end of phase one, which should be the end of  
11 this month, then we'll go to the actual load  
12 monitoring, looking at the utilities loads, the  
13 customers loads, as well as the economics.

14 And then phase three is evaluation  
15 reporting. So this whole project will be going  
16 pretty much parallel, I believe, with the DG OIR  
17 and we're hoping to go through this summer and  
18 probably the following summer, as well, in terms  
19 of our monitoring of DG and I should also say  
20 distributed energy resources. It's not just DG;  
21 we've also got efficiency that we're looking at,  
22 and other pieces.

23 For those of you who are familiar with  
24 San Francisco, we're really focusing on the  
25 southeast part of the City, Hunter's Point,

1 Potrero Hill area. I've got a circle drawn around  
2 our general study area. And our goal is to pick  
3 two feeders within this circle that have  
4 significant penetrations of new DER, or DER that's  
5 already existing, to study. So the actual study  
6 is going to be on feeders even within this smaller  
7 area.

8 Wanted to talk a little bit about how  
9 we're planning on doing this. This is a stylized  
10 feeder load research plan. We're really going to  
11 have four types of metering points. We're doing  
12 this is sort of a real world experiment.

13 WE've got DG units that are  
14 interconnected to our feeder here and here. Those  
15 are number one. We've got energy efficiency.  
16 We've got several power quality meters that can  
17 look at details of what's happening on the feeder  
18 during the operation of the DG and the energy  
19 efficiency. And we've got substation interval  
20 data from PG&E at the end of the feeder to also do  
21 this evaluation.

22 Our research goals are pretty broad  
23 because we've got both the real engineering  
24 analysis -- or analysis on the real engineering  
25 data of the DGs, themselves. And we also have

1       some DER market questions that we would like to  
2       ask, like what types of DG is really going in.  
3       What types of DG are customers really focused on  
4       and excited about. What seems to fit and, you  
5       know, what's out there.

6               There's also quite a bit of load  
7       research, as you can imagine, having all that  
8       interval data from all those points on the feeder.  
9       And we hope to be able to answer a lot of load  
10      research analysis questions on how do you look at  
11      this in terms of what the real impact is of DG on  
12      the system.

13             When this is all rolled up in phase  
14      three and we have a report to talk about we really  
15      want to provide information geared to a number of  
16      different stakeholders, many of which are  
17      represented in this room, including utility  
18      engineers and planners, on what we found out in  
19      terms of DG, at least on these two feeders. I  
20      know there's a limited case of the whole world,  
21      but at least they're real. As well as to the  
22      other folks and stakeholders in the room in terms  
23      of market questions and what types of technologies  
24      are going in.

25             I wanted to go back. I skipped this

1 slide about the researchers on the San Francisco  
2 DER test bed. And the reason why we chose  
3 southeast San Francisco. We're just one of the  
4 partners on there and the lead for E3 is really on  
5 the economics of DG in doing load and research  
6 analysis.

7 Also on our team is Stephen Moss from  
8 M.CUBED, who is the Director of San Francisco  
9 Community Power Co-op. And one of the things that  
10 Stephen's able to bring is a real interface to the  
11 actual customers in the area. They have an office  
12 in Hunter's Point, and this is very much sort of  
13 on-the-ground interaction with customers.

14 We also have on our team ElectroTech  
15 Concepts, who is doing a lot of the engineering  
16 modeling, and is really able to talk a lot about  
17 what the DG interaction is with the distribution  
18 system in a way that distribution engineers  
19 understand.

20 Finally, I want to talk about this third  
21 case study. This is a project that E3 has been  
22 working on for over three years, sometime in 2001.  
23 The New York State Public Service Commission  
24 issued an order for the utilities to issue RFPs  
25 and do an RFP pilot. And we've been involved

1 directly with that with several of the investor-  
2 owned utilities in New York in their response and  
3 helping them develop the RFP.

4 That proceeding is still going. The  
5 utility filings, at least for the utilities that  
6 I'm working with, are going to go this summer. So  
7 I'm not going to be able to talk in a lot of  
8 detail about all the details of what the contracts  
9 look like, and how much the value was and what the  
10 findings were. But I thought it would be really  
11 useful to talk about what the goals of the PSC  
12 order were. And then some of the interactions and  
13 sort of difficulties there were when we're doing  
14 RFPs and integrating, again, DG into the  
15 distribution planning process.

16 The goals of the PFC order was develop  
17 policies and procedures for exactly that,  
18 integrating DG into the utility planning process.  
19 So, in other words, is there a way that we can do  
20 distribution capacity less expensively by  
21 contracting with local DG. Can DG meet the  
22 utility needs.

23 Through issuing RFPs we're going to get  
24 some points in terms of specific information on DG  
25 costs, benefits and impacts. And they wanted

1 specifically to do a range of distribution system  
2 conditions. So this wasn't to be just sort of do  
3 all your RFPs in one type of application, sort of  
4 spread it out. And to determine whether the RFP  
5 process is viable is a good way to do this. As I  
6 said, it was issued in 2001 with evaluation in  
7 three years, which is this year.

8 Our high level findings, local value of  
9 DG is that one, there are areas on the utility  
10 distribution system where DG may provide value.  
11 In super-constrained areas that value can actually  
12 be pretty considerable. If you can imagine  
13 tearing up streets in Manhattan or trying to put a  
14 new substation, that gets pretty expensive. If  
15 you only needed a few megawatts of load reduction,  
16 in order to avoid that you might have a very high  
17 case there for some local DG.

18 The second set of findings that I want  
19 to focus on is well, what are the requirements  
20 that DG has to meet to maintain reliability. And  
21 I think that they're significant. We've talked  
22 about the transmission and distribution avoided  
23 costs earlier with the CPUC efficiency values.

24 There was a couple questions during the  
25 panel discussions about that. And what I wanted

1 to try to talk a little bit about is what that  
2 local planning problem looks like to the  
3 distribution engineer, and sort of how this set of  
4 requirements comes out.

5 In the process of developing an RFP and  
6 sitting down with the engineers and asking, well,  
7 what does DG really have to do, the one thing that  
8 we truly tried to get to was well, let's just make  
9 it clear exactly what we want DG to perform;  
10 exactly where it needs to be and so on, that fits  
11 in with our planning process. And then issue the  
12 RFPs.

13 This is very stylized, but I think it  
14 will get the point across. If you've got this  
15 much existing capacity -- can people see my arrows  
16 -- if you've got this much existing capacity and  
17 your load forecast is expected to exceed that,  
18 then you've got some options. But you've got to  
19 do something.

20 In order to meet your utilities  
21 reliability criteria the sort of traditional  
22 approach might be a new transformer; new  
23 substation; maybe run a new feeder from a  
24 substation that's got some main capacity. The  
25 alternative that this proceeding added is perhaps

1 will add an additional DG unit, okay. And we'll  
2 get some amount of capacity. It's probably not  
3 going to be as much as the sort of normal  
4 traditional utility investment, but it will be  
5 enough to sort of go along.

6 And if you're looking in terms of  
7 contract with DG to provide distribution capacity,  
8 this distance here, this DG provides enough  
9 capacity sort of defines the contract term, okay.

10 Now, I've got the word expected growth  
11 here, and I think on your handout you probably can  
12 see that there's more lines. That's just the  
13 expected growth. One of the issues that we came  
14 up across in New York is well, what happens in the  
15 high growth case, okay. So I've just contracted  
16 my DG for this long-term, say it's five years.  
17 And then the high growth case occurs. You know, I  
18 get new business, I get a lot lower vacancy rates  
19 on my apartments, housing, so on. And I end up  
20 with much higher growth.

21 What that really does is limits this  
22 contract term, okay. So, one of the pieces in our  
23 RFP contract was how long is that going to be, and  
24 so that I'm sure that I'm going to get the value  
25 out of the DG that I was hoping to when I wrote

1 the contract.

2 The other piece that should be clear  
3 from this is that basically the distribution  
4 engineers are relying on that DG to be there in  
5 order to meet the reliability, okay. I know we  
6 were talking earlier, I think somebody mentioned  
7 physical assurance. The approach we took in New  
8 York was to do -- require some redundancy in the  
9 DG capacity in order to provide higher  
10 reliability, something that we called equivalent  
11 reliability to the distribution system.

12 But without reliable capacity it's very  
13 hard to defer that, you basically can't defer that  
14 new transformer and still maintain the system  
15 where you want it.

16 The other piece that I wanted to talk  
17 about here is everybody's been talking about  
18 marginal values, dollar per kW. Maybe the  
19 distribution of avoided costs are \$30 per kW.  
20 When you really look at it and you look at the  
21 distribution planning cycle, what you find out is  
22 that you go in year steps, okay.

23 Ideally you would have everything come  
24 in service just maybe in April before your summer  
25 peak, okay. Once you get through the summer,

1 loads are low and you don't need the capacity  
2 anymore. So planning works on an annual step.

3 So what that means is if you can meet,  
4 and on this chart what I've got is the load  
5 reduction that you can get, and this is just for  
6 one example, and the amount of dollars you can get  
7 in terms of deferring your upgrades, what you find  
8 out is well, you don't get anything, okay, until  
9 you get enough to defer your plans by a year,  
10 right. Now that distribution energy are put off,  
11 they're capital budgeting and they waited a year.  
12 Then you get some value because you can provide  
13 capacity for that.

14 As you get more DG you don't get any  
15 more until you get the second year, okay. And so  
16 on. So, the actual value on distribution  
17 capacity, although we talk about it in terms of  
18 dollar per kW is really a step function.

19 So, if this read dotted line here is the  
20 marginal value, the actual value you always have  
21 to keep in the back of your mind is this step  
22 function. Okay.

23 The other thing to notice is that this  
24 step function falls away from the line. And  
25 that's because there's sort of diminishing returns

1 on more and more capacity because deferral from,  
2 say, year one to year two is worth much more than  
3 deferral from year five to year six. Okay. So, I  
4 mean that's just the net present value, time value  
5 of money kind of fact.

6 So what does that DG requirements  
7 checklist look like. Well, in order to get that  
8 distribution avoided cost value what we found and  
9 what was ultimately, I think, in RFP and contracts  
10 was that, first of all, it has to be  
11 interconnected at the right location and the right  
12 voltage, okay. You've got to be downstream of the  
13 capacity bottleneck or you don't provide any  
14 capacity relief, okay.

15 The way we did that is by providing  
16 maps, okay. DG's got to go within these streets,  
17 and it's got to be connected to a certain voltage  
18 or it's outside of our problem.

19 There's a whole bunch of issues in terms  
20 of interconnection studies. Will DG fit on the  
21 system. How will it work with the system. So, as  
22 part of this, DGs have to go through the  
23 interconnection process that was established in  
24 New York.

25 Equivalent reliability redundancy.

1       There's a couple ways of doing that. One way  
2       that's talked about most I think in California is  
3       physical assurance. We did that through  
4       redundancy. So you may contract with five  
5       generators, but get the firm capacity of three of  
6       them, okay.

7               Dispatch communication. This capacity  
8       is really needed when something on the  
9       distribution system fails, okay. So, in the  
10      planning criteria most utilities plan with some  
11      redundancy. And the sort of industry standard you  
12      may have heard is N-1. But when that thing fails  
13      you absolutely need the DG. And so where that  
14      came out is really to have the DG -- make sure  
15      that the DG is operating within 30 minutes, okay,  
16      of the -- you get notification by the utility. So  
17      we're talking about pretty quick response.

18             If the DG's already running when the  
19      problem occurs, then that's fine, all right. It's  
20      just that you have to be on within 30 minutes.

21             Not only that, well, you have to have  
22      enough capability, right. That should have been  
23      clear from my planning and problem description.  
24      You have to have enough DG in order to really be  
25      able to meet the capacity limit. Or you haven't

1 really created a deferral, right. If you need 5  
2 megawatts to defer of firm capacity and you show  
3 up with 2, the distribution engineer can't delay  
4 their project and still provide the reliability  
5 they need.

6 Last issue was sort of financial  
7 stability of vendor, and the business focus of  
8 vendor, okay. There's some reluctance in the  
9 distribution planning folks, at least those that I  
10 was working with in New York, in terms of turning  
11 over the keys of reliability to somebody whose  
12 main business might be, you know, mixing concrete.  
13 And are they going to really have that generator  
14 there, and are they going to be able to lean on  
15 that and make sure that that's going before they  
16 move their investment plans around. So, I think  
17 that's a big issue in terms of who's responsible  
18 for the ultimate reliability.

19 I think that's the quick summary of  
20 those three projects. And I guess we'll take  
21 questions during the panel.

22 MR. RAWSON: Yeah, we're going to do a  
23 similar structure to last time. We'll hold  
24 questions till all the panelists have presented.  
25 Thank you, Snuller. Peter, you're next.

1                   MR. EVANS: Hi, I'm Peter Evans with New  
2           Power Technologies. I'm going to talk about  
3           another research project; this one is also funded  
4           through Laurie ten Hope's group in PIER. And I  
5           guess it's probably appropriate to say that a lot  
6           of good work is being done in this area. Of  
7           course I'm biased because I'm doing part of it,  
8           but some credit needs to be given for the folks at  
9           PIER, and I think especially Laurie and Linda  
10          Kelly, who I work with; who, for funding some, at  
11          the time, were pretty innovative ideas that now  
12          are beginning to look like they might be pretty  
13          useful. And hopefully you'll find this as one of  
14          them.

15                 When we started this project we were  
16          sort of front-running some of the questions before  
17          this Commission, before this proceeding, but what  
18          are the potential distributed energy resources  
19          benefits in terms of enhanced performance to the  
20          power delivery network. Can these be reliably  
21          measured in value. What are the specific size,  
22          location and operating profile of DER projects.

23                 I see some squinting, and I bet you  
24          can't read the handouts you got, either. Oh, no,  
25          I see it looks like a few people have more full-

1        sized ones. I think this is posted, but anyway I  
2        apologize for the type size.

3                What are the specific size, location and  
4        operating profile of DER projects that contribute  
5        the most to network performance. What are the  
6        most consequential barriers to these projects.  
7        And how can utilities provide incentives for  
8        beneficial DER projects based on value sharing  
9        rather than cost shifting. And, of course, this  
10       last one goes directly to this proceeding.

11               A couple people have mentioned this. I  
12       don't think it can be repeated too many times.  
13       That benefits of distributed generation accrue to  
14       different stakeholders. And you have to be very  
15       careful about who you're talking about.

16               Now I personally am not a fan of sort of  
17       global optimization. I simply look at it and say  
18       that the customers are a stakeholder; they're an  
19       independent actor. The utilities are a  
20       stakeholder; they're an independent actor. The  
21       entire focus of this study is what's good for the  
22       network, and by proxy, what's good for the  
23       utilities. And we did that intentionally.

24               I guess I'd also say, though, in  
25       response to some of the questions in the first

1 half of this, that I think the overlap between  
2 these, what's good for the network and what's good  
3 for the customer, probably is pretty big. And I  
4 don't see these activities as being distinct. I  
5 don't see utilities necessarily out doing things  
6 that are good for the network, and having that be  
7 separate from customers doing things that are good  
8 for customers. I think what we should do is try  
9 to find the overlap.

10 But this, again, is just looking at the  
11 network. I think I counted six or seven studies  
12 in the report that Chris talked about that talked  
13 about how to figure out what's good for customers.  
14 So I think this is pretty well trodden.

15 In this particular study we took a  
16 couple of different approaches. First of all  
17 we're looking at the power delivery network where  
18 DER projects are actually connected. That is at  
19 the distribution level. But we look at the  
20 distribution and transmission as an entire  
21 integrated circuit or integrated network because  
22 what we want to see is how DER at the distribution  
23 level provides benefits or creates problems at the  
24 transmission level. Or how transmission level  
25 problems can be remedied through DER

1 implementation at the distribution level. Again,  
2 we want to have a comprehensive assessment of the  
3 network benefits, both at the transmission and  
4 distribution level.

5 The second thing, we also considered  
6 demand response in addition to distributed  
7 generation. So when I talk about DER I'm actually  
8 talking about demand response, distributed  
9 generation and also capacitors.

10 We wanted to look at a broad set of  
11 benefits, but again all network related. So  
12 voltage profile improvement, reduced reactive  
13 power flows, reduced electrical losses, stability  
14 and power quality improvement. We didn't actually  
15 look at reliability the way Snuller defined it,  
16 although conceivably we could. And then also we  
17 wanted to look at avoided or deferred network  
18 additions, although we took what sounds like a  
19 little different approach to that, and I'll come  
20 back to that.

21 And then lastly, and I'll talk about  
22 this some more, is we used a new analytical tool  
23 developed by optimal technologies which allowed us  
24 some insight into what's going on in the network.  
25 And an optimization level, I guess I should say,

1       that I don't think is achievable through any other  
2       means.

3               Silicon Valley Power, I think we've got  
4       all the munis in the Bay Area pretty much  
5       represented. I don't know if there's a lesson  
6       there. I think there's a lesson there, but I'm  
7       not going to say what it is. But, in any case,  
8       Silicon Valley Power was the host. And they  
9       provided all their system data for us.

10              And to give you an idea of what we did  
11       with this, the WECC characterizes the Silicon  
12       Valley Power system as two 115 kV busses with  
13       their loads and generators basically hung off  
14       those two busses.

15              Silicon Valley Power, themselves,  
16       characterizes their own system as 80 115 kV and 60  
17       kV busses with loads basically hung off the  
18       stepdown transformers.

19              So, what we did is we characterized --  
20       again, we want to see the system the way  
21       distributed generation is going to affect it. So,  
22       that's fundamental to this approach.

23              We characterized the SVP system as an  
24       850 buss network ranging from 115 kV, 60 kV and 12  
25       kV distribution. There's about, I think I counted

1 960-some line segments; 48 12 kV distribution  
2 feeders, that's about half their system; 106  
3 switchable branches connecting them. This is a  
4 highly networkable system, even though it's  
5 operated radially, it's network-able.

6 There's 422 customers, if you want to  
7 call it that. They're basically stepdown  
8 transformers going to customers. And also  
9 customer at primary voltage service. There are  
10 six generators embedded in the system now, but we  
11 characterized them as having individual megawatt  
12 and megavar capability.

13 There's 101 switchable capacitors. Now  
14 in reality SVP system the capacitors are  
15 switchable if you drive a truck out to change  
16 them, most of them, a couple of them are clock-  
17 operated. But we wanted to play with them, so we  
18 said they were switchable.

19 And then we used the actual customer  
20 loads and generation levels down to the individual  
21 feeder level from their SCADA, so that I'm going  
22 to talk about specific hours in a specific year  
23 where we determined what the actual condition of  
24 the system was on those hours based on their own  
25 SCADA. And then this whole network was fully

1 integrated into the 15,000 or 13,000 buss WECC  
2 western grid, which also includes the PG&E  
3 regional system.

4 This is the basecase which was summer  
5 2002, which was the first case we did. This is  
6 the way SVP would look at it at the transmission  
7 level only. And what you can see, this is a  
8 voltage profile. I'm going to show you a couple  
9 that look like this. And these are just points on  
10 the system more or less organized geographically.  
11 They have a south loop, a center loop, a core and  
12 a north loop for their transmission system. And  
13 so these are oriented in a more or less  
14 geographical way.

15 It's hard to characterize a network  
16 system with a line, but this is an attempt at it.  
17 And then the left-hand index is the voltage at  
18 each one of these locations in the system on a  
19 per-unit basis.

20 So, for example, if it's supposed to be  
21 a 12 kV buss and it actually has 12 kV at that  
22 buss, then that's 1.0 per unit voltage. So this  
23 allows us to sort of step back and look at the  
24 voltage characteristic of the entire system.

25 And what you see here is that the

1 voltage is pretty close to 1 through most of the  
2 system. This is a lightly loaded system; there  
3 aren't known problems with it. We didn't come  
4 here to fix problems; we came here to test the  
5 methodology, so keep that in mind as you look at  
6 these results.

7 But keep in mind also that customer-  
8 sponsored distributed generation and demand  
9 response wouldn't be visible on this plot because  
10 they'd be on busses that aren't represented here.

11 So this is the way we looked at it.  
12 It's far more detailed. But what you can see here  
13 is by integrating in the distribution, so going  
14 from 80 to 850 busses we find that there's a lot  
15 more low voltage busses, a lot more voltage  
16 variability within the system, and voltage  
17 variability within individual feeders.

18 So, for example, something like -- you  
19 guys can see these pointers, right -- down here,  
20 this is the point where the feeder connects with a  
21 60 kV, a 12 kV transmission to distribution  
22 stepdown point And then as you work your way out  
23 the feeder you can see that the voltage not only  
24 varies along the feeder, but it declines. And  
25 this particular feeder is actually pretty low

1 voltage.

2 It's not a problem, I wouldn't say, from  
3 an engineering standpoint, but an opportunity for  
4 optimization. This sort of resolution you  
5 wouldn't get in this traditional look; you just  
6 don't see it.

7 So our objective to improve network  
8 performance we had to be a little bit careful  
9 about what it is we're really doing, because I was  
10 thinking ahead to being able to quantify these  
11 benefits. And so we tried to be pretty  
12 disciplined about what it was we were going to do  
13 before we started to do it. And so we established  
14 an objective to minimize real power losses and  
15 reactive power consumption simultaneously, while  
16 also eliminating low voltage busses and flattening  
17 the voltage profile overall.

18 That can be characterized in  
19 mathematical terms, but conceptually that's what  
20 we wanted, that's what we called network  
21 improvement, was making steps in that direct. So  
22 it's a simultaneous optimization for  
23 mathematicians; and for planners, it's making it  
24 better.

25 We also wanted to not take credit for

1 distributed generation and demand response for  
2 things that could be corrected for existing  
3 controls. Now, we had a level of sophistication  
4 in evaluating those controls that goes well beyond  
5 what the utility had.

6 But we actually made ourselves reset all  
7 the variables that were set-able in the system to  
8 optimize ahead of time. And then measured the  
9 impacts of adding new distributed resources.

10 So, for example, all the capacitors we  
11 set at the optimal points. In some cases we  
12 turned them off; in some cases we turned them on.  
13 We also adjusted the reactive power output from  
14 the existing generators to optimize the system as  
15 best we could before we started adding stuff.

16 We looked at reactive capacity  
17 additions, basically additional capacitors in  
18 standard sizes. We looked at demand response, and  
19 we wanted to characterize this in a way that was  
20 reasonable. These are somewhat arbitrary,  
21 although CEC-approved assumptions.

22 Where demand response we said that it  
23 was limited to 2 to 15 percent of the load,  
24 depending on the size. So larger customers were  
25 capable of more demand response. And under

1 certain conditions. For example, we said more  
2 capable at that level of demand response all the  
3 time, but in certain cases they were. We wanted  
4 to see the impact of sort of extraordinary demand  
5 response, if you will.

6 And then also for distributed generation  
7 additions we characterized these all as  
8 synchronous capacitors or synchronous generators,  
9 so that there was both megawatt and megavar  
10 capability from these units. That's also an  
11 arbitrary assumption, but there's a lot more you  
12 can do with reactive power from a distributed  
13 generator. So, we wanted to use that degree of  
14 freedom.

15 And then we also limited distributed  
16 generation to 60 percent of the host load, and  
17 subject to limits so that the feeders wouldn't be  
18 exporting feeders. And this is a pretty  
19 controversial set of assumptions. I think it's  
20 the market, and I think it's the future, but  
21 that's one person's opinion.

22 But for those who see distributed  
23 generation as being a source of exporting power,  
24 we didn't assume that here. And so that would be  
25 a different study to look at what those impacts

1       might be. I was trying to stay clear of people  
2       saying that there's issues with interconnection  
3       that you haven't considered. I was basically  
4       trying to pick the space that's easy  
5       interconnection, relatively low impact on the  
6       system; trying to avoid negative impacts.

7               Now, with this detailed analysis we can  
8       actually go down to line segment by line segment  
9       and see where the problems are in the system. But  
10      we used this AEMPFAST analysis which actually  
11      identifies, through this multivariable  
12      optimization, the specific locations on the  
13      system, buss by buss, that contribute -- where  
14      capacity makes the most contribution to the  
15      objective, the optimization objective that I  
16      characterized earlier.

17             So this is a plot of the index, if you  
18      will, going across the system. The value of  
19      adding, in this case, real power capacity at each  
20      buss on the system. The value being its ability  
21      to make an improvement in the objective that I  
22      described, the mathematical objective that I  
23      described.

24             And so you can see here the high points.  
25      There's a couple of specific locations on specific

1 feeders coming off specific substations and  
2 specific parts of the system that kind of jump  
3 out. And then one that's a low point where it  
4 happens that they have a couple of relatively  
5 large distribution-connected cogeneration units  
6 already there. So basically that's a bad place to  
7 add additional real capacity. And then the ones  
8 on the top are good places, beneficial places to  
9 add real capacity.

10 And what we found by going through  
11 looking first at demand response, we identified  
12 382 locations. We could rank order them, 1 to  
13 382. And this plot shows the top 20.

14 But what this shows is the locations,  
15 individual busses, but also which feeders they're  
16 on where demand response contributed the most to  
17 network performance. And these are listed in rank  
18 order. But what you can see here is that there's  
19 a lot of them on that core 1 feeder 305, which if  
20 you go back was one of the ones that was  
21 identified in the prior plot. And then also north  
22 to feeder 202.

23 But, again, these are specific locations  
24 on the feeder. In the case of feeder 305 the way  
25 that works is these rank orders, basically you're

1       working from the outer end of the feeder in. And  
2       the reason why that feeder is ranked so highly is  
3       because if you add capacity to that feeder, not  
4       only does it benefit that feeder, but it benefits  
5       the entire system.

6               There's a lot more of cross-system  
7       impact of these changes than I expected. And I  
8       think that most people believe, looking at these  
9       feeders are part of a network, shed some light  
10      that it's probably kind of new.

11             This is just another way to look at  
12      these, basically. these are the top feeders in  
13      terms of the number of busses that appear in the  
14      top 100. It's just a way to identify, since this  
15      was a lightly loaded system, the benefit  
16      difference from location to location is tiny.  
17      It's just a mathematical difference.

18             So there's a number of ways to slice and  
19      dice the results to get the same sort of picture  
20      that you would get in Snuller's plot where you  
21      say, okay, these are the areas that are most  
22      valuable for adding resources.

23             We did the same thing for distributed  
24      generation. Basically ran an analysis that  
25      identified the top locations, the most beneficial

1 locations for distributed generation.

2 In this case, depending on the upper  
3 limit we set, under rule 21 which limits  
4 generation on a feeder to 15 percent of the peak  
5 load, there's 124 locations in the system that  
6 benefit the system.

7 And then we also set a different limit  
8 which is basically limit the generation added to a  
9 feeder to the light load on that feeder. So,  
10 again, it's not exporting, but it's a more -- a  
11 less restrictive limit. And that identified 346  
12 locations. And this is the same kind of ranking.

13 And you can see here that some of these  
14 projects, in fact most of them, are pretty small.  
15 We were limited to 60 percent of the host load,  
16 but the second ranked project is a 7 kilowatt  
17 project on a 14 kilowatt load. It just happens to  
18 do with the location of that load and the benefits  
19 that adding capacity at that location have to the  
20 entire system.

21 These two plots, which I can't even read  
22 them, myself, but suffice it to say that as you go  
23 through and simulate the system adding these  
24 pieces of capacity one by one, we see a continuous  
25 improvement not only in losses, but also in the

1 overall performance of the system as measured by  
2 the objective.

3 And this gives you a picture again, the  
4 blue line is the voltage profile as we found it.  
5 And the, I guess it's brown, or the top line in  
6 most cases, is the voltage profile with the  
7 addition of both distributed generation and demand  
8 response.

9 And what you see is by adding these, not  
10 only do we reduce losses, which was shown in the  
11 prior slide, but we also have flattened the  
12 voltage profile and raised it through the addition  
13 of these resources at these specific locations.

14 So this was a sick system that had the  
15 voltage profile all messed up. These would be  
16 very very valuable improvements.

17 So the combined effect, for those of you  
18 who are interested in things like penetration,  
19 taken all told, the demand response was about 3.4  
20 percent of total peak load, so a modest amount.  
21 And the distributed generation was about 9.7  
22 percent of peak load, again a modest amount.

23 A lot of sites, 382 customer sites for  
24 demand response and 346 customer sites for  
25 distributed generation. So this is a big diverse

1 population of projects. They, together, resulted  
2 in -- and this is after the recontrol improvement  
3 that we made -- a 31 percent reduction in real  
4 power losses in the system; 30 percent reduction  
5 in reactive power consumption.

6 We reduced losses at three times the  
7 system's average lost rate, so there's a leverage  
8 going on here. It's not just throwing capacity  
9 and reducing imports. We're adding them in the  
10 right spot and achieving a loss reduction at three  
11 times the average rate of the system.

12 In addition to the losses within SVP we  
13 saved about 5 megawatts of losses in the  
14 surrounding PG&E system. We eliminated all the  
15 busses in the system that were below 1.0 per unit,  
16 so any low voltage busses, we eliminated them.  
17 And we also reduced the variability in the voltage  
18 profile, flattened it.

19 So these benefits are significant; they  
20 can be quantified. And, you know, they're real  
21 benefits to this network.

22 Now, we're going to do more with this.  
23 This is in process. But we want to identify the  
24 impact of these capacity additions on the  
25 network's load serving capability under

1 contingency conditions. That's a standard metric  
2 for measuring transmission or distribution  
3 expansion needs. And I think I -- I'm pretty  
4 confident that the network, with these additions,  
5 has a higher load serving capability.

6 We also want to look at the benefits or  
7 dis-benefits, as the case may be, under offpeak  
8 conditions. And also how the benefits change if  
9 we add in load growth.

10 But what really this is about is what's  
11 the value of these benefits. This goes to  
12 Commissioner Geesman's question. Electrical  
13 losses, obviously, are easily priced. It's just  
14 the value of the energy that you save.

15 Reduced queue consumption is relatively  
16 easily priced, as well, although it's not very  
17 valuable in terms of its replacement cost. The  
18 increased load serving capability under  
19 contingency conditions, in this particular case  
20 the utility had network improvements that it  
21 either implemented or is considering implementing,  
22 so we can trade off the benefits of the system  
23 with this DER penetration versus actual projects  
24 that they're considering, and see whether we can  
25 achieve the same performance without actually

1 making improvements.

2 But one of the things that I sort of  
3 throw out as a challenge for this proceeding is  
4 that there's some other things that are a lot  
5 harder to value, and may ultimately be more  
6 important. And I won't to tick these off  
7 individually, they're listed here.

8 But one of the things to think about is  
9 this approach allows us to optimize voltage and to  
10 reduce voltage variability across the system. The  
11 additional resources in the system allow a lot  
12 more close control of that voltage, and closer  
13 management of that. And voltage is what causes  
14 systems to fail. It's not lack of resources.

15 The Northeast blackout was maybe caused  
16 by tree-trimming, but the thing that made it  
17 possible was the voltage on the system was messed  
18 up.

19 And the benefits of distributed energy  
20 resources to manage voltage within a system could  
21 be enormous. And there's no way to value that  
22 that I can think of. And it would be a shame to  
23 simply have it slip away, because this is an  
24 essential feature to managing a modern system.  
25 The alternative is to over build it like we do

1 now.

2 So our conclusions. DER can benefit the  
3 power delivery system. These things can be  
4 quantified and priced. Doesn't matter what the  
5 generator is as long as you characterize its VAR  
6 production capability and its unit operational  
7 characteristics, when it's available, when it's  
8 not, those types of things. But where it's placed  
9 in the network is exceptionally important.

10 And then some thoughts on okay, what do  
11 you do with all of this in terms of creating  
12 tariffs that implement this. In my mind, this is  
13 the reason this is in here, in part, is because  
14 this is ultimately part of our deliverable under  
15 our project to the Commission.

16 But I think that in my mind it's  
17 possible to offer location-based incentives based  
18 on this type of an analysis. The utility could  
19 offer location base incentive, basically dollars  
20 per kilowatt installed at a particular buss or  
21 particular busses in an area, subject to a  
22 particular specification for the unit, its minimum  
23 size and its lead lag VAR capability.

24 Specifications have to do with its fit  
25 into the network, that is it's nonexporting based

1 on the host load and the feeder limits. And some  
2 operational characteristics, that is 80 percent,  
3 let's say, online during peak hours; it's  
4 curtailable during offpeak hours; and the real-  
5 time variable reactive power production is  
6 variable by the utility based on telemetry.

7 I don't subscribe to the notion that  
8 every one of these units has to be directly  
9 controllable by the utility. If you have 350 of  
10 them, they're a population that, you know, taken  
11 together, they're not all going to quit at once.  
12 And then leave everything else up to the customer  
13 or the developer.

14 And second idea is if there is  
15 identified congestion within a system for which  
16 there's an identified network fix, like a new  
17 transmission line or a new distribution line, why  
18 not put that information out to bid and see  
19 whether the money that would have been spent on  
20 that or a portion of the money that would have  
21 been spent on that might be better spent as an  
22 incentive for non wires congestion relief.

23 So, that's all I have.

24 MR. RAWSON: Thank you, Peter. And our  
25 last presenter for this panel is going to be Ellen

1 Petrill.

2 MS. PETRILL: Thank you, Mark. Hi, I'm  
3 Ellen Petrill from EII. We're an affiliate of  
4 EPRI. And I'm going to talk today about costs and  
5 benefits of DER in the context of developing  
6 win/win/win approaches. And I'll talk more about  
7 what that means.

8 But first I want to share some credit  
9 for the project that we're doing with Dan Rastler  
10 from EPRI, John Nimmons, who's a consultant in our  
11 project team lead, the famous Snuller Price, who's  
12 been here all day. We're pleased to have someone  
13 with the expanded experience you have on our team.  
14 Also Jim Torpey, who's a consultant; and Rick  
15 Weston from RAP. So a broad team and a broad set  
16 of stakeholders that we're working with.

17 So, I'm going to talk about our project  
18 and then show you some of the tools that we're  
19 using to go forward with the project. So we're  
20 working on integrating DER into the market. What  
21 are ways to get over the barriers that are out  
22 there. And our project is a stakeholder-driven  
23 project. And they told us that the work that we  
24 needed to focus on, that a public/private  
25 partnership could focus on, is finding win/win

1 approaches. How can all the players get a stake  
2 in this business.

3 And, of course, win really means  
4 financial gain. There's a lot of other things  
5 that we all talk about, but you got to have some  
6 dollars for each of the stakeholders. And our  
7 definition for win/win, we talk about win/win or  
8 win/win/win, and I'm going to shorten it to win/  
9 win. But there are three parts of the stakeholder  
10 process that I'll talk about. Each of them should  
11 have a win. And nobody can lose; I mean that's  
12 the key point. For a real win/win there has to be  
13 multiple winners, and nobody can be worse off.

14 On the project our approach is to  
15 develop some tools that will help stakeholders  
16 find these win/win. And our approach is to bring  
17 the stakeholders together to guide the project,  
18 and also to help develop these win/win  
19 opportunities.

20 So, we started the project in 2003. A  
21 number of you here today have helped us. We've  
22 developed a catalogue of approaches and a cost/  
23 benefit model, and I'll show you some of that  
24 today. And also a framework for how you bring  
25 stakeholders together so you can collaborate, and

1 again develop these win/wins.

2 The next step is to try it out with a  
3 pilot project. And so we're building a pilot  
4 project in California with stakeholders, working  
5 with Southern California Edison and many of you  
6 here in the room today. And I'll talk more about  
7 that.

8 We're exploring some ideas in New York,  
9 but we don't have very much formed yet. And as we  
10 go further we may have something that we could do  
11 there. But we're focusing on California now. And  
12 we're really pleased that this project can help  
13 feed this proceeding.

14 So, in the project we have partners and  
15 stakeholders, and we're really happy with the big  
16 number of participants who we're working with.  
17 There's government entities, and as Mark has said,  
18 this project is funded by PIER in Laurie ten  
19 Hope's area, and Mark Rawson has worked very  
20 closely with us. NYSERDA is also a funder. The  
21 Massachusetts Technology Collaborative is also a  
22 funder, and we've worked with DOE, too, to support  
23 this.

24 And others have participated with us.  
25 The New Jersey Board of Public Utilities is also

1 working with us. And we've had input and support  
2 from many other regulators and organizations that  
3 work with regulators. Also manufacturers, you can  
4 see there; and utilities, TVA, the -- well, I tend  
5 to call them utilities, but they're not all  
6 utilities. In fact, when we talk to utilities  
7 they say, what do you mean by utility. These days  
8 it really means something different for every kind  
9 of organization.

10 So we have the New York ISO working with  
11 us, as well; Ameren, NYPA and City Public Service  
12 of San Antonio. Those are our funders. And then  
13 many others that have worked with us very closely  
14 on providing input, reviewing materials. And  
15 we're working on a project with Southern  
16 California Edison. And we really appreciate their  
17 support and work with us.

18 Developers, RealEnergy, DT Energy  
19 Technologies. Consumers, Silicon Valley  
20 Manufacturers Group have worked with us. And  
21 NGOs. So it's a broad group.

22 So those are our stakeholders that are  
23 part of our project. But when we look at a  
24 cost/benefit analysis, who are the stakeholders  
25 that are important here.

1 Well, I'm a mechanical engineer, not an  
2 economist, and so I tend to draw control volumes  
3 around things. And so the control volume we're  
4 drawing around this set of stakeholders, it's kind  
5 of like a little ecosystem that's very tightly  
6 connected. It is the end-use customer who might  
7 buy the distributed energy resources or DG unit;  
8 the utility, although the utility really means the  
9 shareholders; and the other ratepayers in the  
10 system.

11 So there's not really a utility that's a  
12 stakeholder, it's the utility and the flow to the  
13 shareholders and other ratepayers. And then  
14 there's society. So this control volume really  
15 includes everybody, everybody in this room is part  
16 of this control volume.

17 But note that I also drew on the outside  
18 the DER suppliers or developers, or the ones that  
19 sell the equipment or either provide the service.  
20 They're kind of on the outside of this control  
21 volume. Does that make sense to you?

22 Okay, so what is a win/win/win. We're  
23 looking at those three types of stakeholders.  
24 Well, obviously it has to be a win for the  
25 customer. But it also has to be a win for the

1 utility shareholders and ratepayers. And you can  
2 get there a number of ways, and rate design might  
3 be one, a custom contract might be one. We're  
4 looking at other possibilities, as well.

5 And we also want to see the win overall  
6 for society. So it could be cleaner environment,  
7 lower total cost. So the win/win/win means  
8 everybody has to get something positive.

9 Let me describe to you our process.  
10 Here's another slide that's hard to read. I'll  
11 just walk through it. This is a process to  
12 develop or identify win/win opportunities. First  
13 you identify the key stakeholders.

14 So I'm going to contend that we start  
15 with a project, a specific project. Then let's  
16 just say in a customer location in a utility  
17 distribution planning area that would be grid  
18 connected, or could be grid connected. So those  
19 are the stakeholders, the customer and the  
20 utility. And then society has to be considered.

21 So, we would put the specifics of the  
22 project into our modeling tool. I'll show you  
23 what that looks like in a moment. And we'd use it  
24 to estimate the costs and the benefits for each  
25 stakeholder.

1           The first question that you ask is does  
2     the DER, does this specific project provide a net  
3     societal benefit. So does it cost less than other  
4     alternatives, are there environmental benefits.  
5     So, overall, is there a net societal benefit.

6           If the answer is no, then we contend  
7     that you can find, you may be able to find ways to  
8     leverage the value of that DER. And we've talked  
9     about those today. Are there ways to support  
10    customer needs as well as grid needs. So if you  
11    can find a way to leverage the DER, then you  
12    probably can get a net societal benefit.

13          Then you go down to the next question  
14    which is, is there a net benefit for each  
15    stakeholder. And if the answer is no, then we  
16    would contend you can design some efficient  
17    incentives to share among the stakeholders. So is  
18    there something that the customer is gaining that  
19    could go back to the other ratepayers. Or is  
20    there a benefit that the utility could provide as  
21    an incentive to the customer to go ahead and put  
22    that DG unit in.

23          And if we get to a yes, then there is a  
24    net benefit for each stakeholder, then we may have  
25    to eliminate some barriers, those are related to

1 interconnection, permitting, that kind of thing.  
2 Our project's not focusing on those, but we don't  
3 want to assume that they aren't still there in  
4 some way. Then go ahead and implement the win/win  
5 solution.

6 Okay, so we've put a cost/benefit model  
7 in place to take that approach. And obviously  
8 overall the benefits have to outweigh the costs to  
9 find a win/win.

10 I've listed some costs and benefits that  
11 we consider quantifiable or fairly easy to  
12 quantify. I don't think I need to describe those.  
13 Some things that are harder to quantify we've  
14 heard about today from the customer point of view.  
15 The customer reliability, power quality, price  
16 risk management, peace of mind, some of these  
17 things are harder to quantify. But possibly could  
18 be quantified on a case-by-case basis.

19 From the utility shareholder and other  
20 ratepayer perspective, system reliability is  
21 important. The system quality, possibly voltage  
22 support, some of the other things that Peter was  
23 just talking about.

24 From the society perspective, system  
25 reliability, again, environmental benefits.

1 Again, the total resource costs.

2 Okay, let's take a look at the tool.

3 This is the output sheet of an Excel spreadsheet.

4 It's essentially a calculator to help you keep  
5 track of costs and benefits from each of those  
6 stakeholders' point of view.

7 So the top section up here is the DG  
8 customer. And this side, the left side is the  
9 benefits. And this is the total costs.

10 So in this case, this happens to be a  
11 case using some real data, but it's not a real  
12 project, in a PG&E constrained area. So the  
13 project showed that there would be some  
14 electricity bill savings here. Note that the  
15 benefit for one stakeholder is a cost to another.  
16 So that turns out to be the same number as the  
17 revenue reductions for the utility shareholders  
18 and the ratepayers.

19 But there is the biggest benefit over  
20 here, an avoided T&D capacity. So in this case,  
21 we just jump down to the bottom, there is a  
22 positive societal benefit, this bottom box is  
23 green. But there wasn't a net benefit for each of  
24 the shareholders. So this project may not go  
25 ahead because the customer doesn't get a big

1 enough benefit.

2 But what could you do. Well, that's too  
3 big. So we propose that one way to look at this  
4 is for the utility shareholders and other  
5 ratepayers to share some of the benefits of the  
6 T&D deferral. So provide an incentive or a credit  
7 to the DG customer. And so this new value, this  
8 73 -- and these units are dollars per megawatt  
9 hour -- 73.33, \$73.33, came right out of the  
10 utility shareholder tally sheet, okay.

11 So now it becomes a cost to them. But  
12 what that does is put the overall benefit on the  
13 positive side for the customer. So that incentive  
14 may be enough to get the customer to install that  
15 unit.

16 Now, this requires that the DG customer  
17 is willing to provide the DG unit as needed in  
18 peak times. So there's physical assurance that's  
19 needed to provide that. So it depends on the  
20 contract and agreement that's set up between the  
21 utility and the customer.

22 So, this tool is intended to show you  
23 how we could go about finding win/wins, and this  
24 is just one example.

25 There's another one in the set. This

1 is -- I'll go through here quickly -- this is the  
2 Southern California Edison example of CHP. Now,  
3 this looks at how rates can have an impact. This  
4 turns out positive for the customer, but not for  
5 the utility. And the solution that we came up  
6 with for this one was to change the rate -- these  
7 rates, it turns out, aren't being used at the time  
8 -- but the changed rate had more, a larger portion  
9 of the rate went to fixed charges than demand or  
10 energy charges. So it changes the outcome on both  
11 sides, as well as you can see an incentive. So  
12 the rate change and there was an incentive right  
13 there; the cost here is a benefit right there; the  
14 16.67. Turns out with a positive for each of the  
15 stakeholders.

16 So, I'm not saying that these are the  
17 solutions that we're going to find, but this is a  
18 way that you can find win/win solutions.

19 So, our project that we're developing  
20 with Southern California is to support development  
21 of an RFP that will come out this fall that will  
22 receive some successful bids. So we heard Snu  
23 talk about the New York experience. What we want  
24 to do is bring stakeholders together and talk  
25 about what would work. What are some win/win/win

1 possibilities.

2 And so this project will test out the  
3 stakeholder collaboration process. Hopefully it  
4 will identify some true win/win/win solutions.  
5 And then we can take that experience and scale it  
6 to other parts of California or other states.

7 So our approach is to share a  
8 transparent analysis. We heard about that earlier  
9 today. But we're going to work with Edison on  
10 understanding specific distribution planning area  
11 needs; do calculations on what the traditional  
12 costs would be to build those out with using  
13 traditional approaches; and then use our cost/  
14 benefit analysis to develop some potential win/  
15 wins.

16 And we're going to bring stakeholders  
17 together to take a look at those, and maybe  
18 innovate beyond those. Maybe there's some other  
19 ideas that we hadn't even thought of.

20 So we're looking to kick that off with a  
21 stakeholder workshop in mid July. And then the  
22 RFP is planned to come out in October. And we'll  
23 monitor the results and put a report out to keep  
24 you all posted.

25 So one of the outcomes will be what are

1 the cost/benefit analyses that come out of those  
2 win/win examples.

3 So, the conclusions that we have to date  
4 are in a regulated environment costs and benefits  
5 are in the eye of the beholder, because a cost to  
6 one may be a benefit to another. So obviously, in  
7 reverse, a benefit to one is a cost to another.

8 And enabling true win/win/win approaches  
9 requires a quantified cost and benefits. We all  
10 know that. So, we're taking a step on that with  
11 our calculator tool to understand what they are.

12 We think that at least at this moment  
13 costs and benefits can be quantified on a project-  
14 by-project basis. And that's the way to do it.

15 And those harder to quantify costs and  
16 benefits like the reliability from the customer  
17 point of view and the system point of view, they  
18 might be able to be quantified also on a cost-by-  
19 cost basis, and we think they need to be worked on  
20 together with the stakeholders.

21 So, thank you.

22 MR. RAWSON: Thank you, Ellen. I think  
23 we're going to do the same as we did before.  
24 We're going to have questions and answers for the  
25 panelists. And, I again remind everybody that

1 we're keeping a transcript, so it's important to  
2 use the microphones; come up to the microphone and  
3 ask your question. Please state your name and  
4 affiliation.

5 We have about 20 minutes for the Q&A  
6 session, so I guess I'll ask first if there's any  
7 questions up front? None. Any questions out  
8 here?

9 MR. MAZUR: My name is Mike Mazur and I  
10 represent 3 Phases Energy Services. We are an  
11 energy service provider and have direct --  
12 customers load. And I have a question for Peter.  
13 It was a very impressive presentation, by the way,  
14 of your project.

15 I want to understand if I got the  
16 numbers correctly. You said you reduced losses in  
17 31 percent?

18 MR. EVANS: I believe so, yes.

19 MR. MAZUR: And also you mentioned you  
20 reduced 5 megawatt for PG&E losses, as well,  
21 correct?

22 MR. EVANS: That's correct.

23 MR. MAZUR: Okay.

24 MR. EVANS: In the case of SVP 31  
25 percent, I forget what the overall loss percentage

1 was, but it was relatively low.

2 MR. MAZUR: I did a very rough  
3 calculations based on future dollar per megawatt  
4 on some real time prices and I come up with for 5  
5 megawatts for PG&E it brings them \$5000 a day on  
6 saving, if they save 5 megawatt in losses, just  
7 for your project, okay. \$5000 a day gives you  
8 about \$150,000 a month, so it can bring ten more  
9 lawyers to support. Just PG&E alone.

10 And probably utility companies don't --  
11 and they have very valid point from reliability  
12 standpoint they have, today they have big  
13 advantage of not letting distributed generation  
14 online because of reliability, responsibilities  
15 and safety issues and stuff.

16 But then you talk money -- when you talk  
17 money with them they let you do certain things  
18 like this. And this project sets a very good  
19 example how to approach innovatively distributed  
20 generation concept based on losses and money and  
21 dollars.

22 And that will make a utility move.  
23 That's what they want. They all want essentially  
24 utility to start moving forward with distributed  
25 generation.

1           I want to make one more point. By the  
2       way, did you try to sell efficiency on the real  
3       market, -- efficiency on the real market  
4       framework? Because that's possible. You have all  
5       the information and technology tools. And it  
6       might be part of the project, maybe next project,  
7       start selling online.

8           MR. EVANS: Well, on that particular  
9       one, if I understand your question correctly, the  
10      thing we didn't do was assume that there was any  
11      output from the embedded generators that would  
12      find their way back out to the system. Basically  
13      all the production will be used by those  
14      customers.

15          MR. MAZUR: Just an idea. Yesterday in  
16      South Bay it was about \$200 per megawatt, some  
17      hours, okay, because it was a very hot day. You  
18      might consider -- customer might consider taking  
19      tariff price and sell excess electricity out and  
20      make some money out of that. That's just  
21      something in real time, but some ideas.

22          We can do that today based on  
23      technology. We just need regulations and rules in  
24      place.

25          Now, having said that, RMR is an example

1       which I saw exercised today, reliability must run  
2       program. But unfortunately, they do not accept  
3       generators less than 10 megawatt to play this  
4       game, or make some quick return on investment for  
5       small generators.

6               If utility company consider like we  
7       discussed a little bit today, network, going down  
8       the line, less than 10 megawatt, going to other  
9       circuitry, this concept might benefit them, as  
10      well.

11              So this is the kind of point I want to  
12      make, and thank you.

13              DR. ELY: Dick Ely again, Davis Hydro.  
14      I will be brief. Snuller and Peter, just one  
15      thing I wondered if you would address. One of the  
16      bugaboos in this whole evaluation process is the  
17      utility comes back and he says, yes, you've done a  
18      very good job in analyzing the savings during  
19      normal operation, and even transient operation.  
20      But the reality is we can't cut any distribution  
21      equipment because of black start requirements.

22              I wonder, have you incorporated, or will  
23      you be incorporating the black start capability  
24      and the black start requirements as part of your  
25      analysis.

1           The other thing I'd like to pick up on  
2       what Mike just mentioned, is that utilities, in  
3       general, have a great number of very small  
4       customers they're selling to. But one of the  
5       major bugaboos of this process is distributed  
6       generation is also small, especially green  
7       generation.

8           And something not addressed here, except  
9       by Mike briefly, is that most of the  
10      opportunities, as in most of the selling of  
11      electricity, is from small generators. And it  
12      would be good if the analyses or some of the work  
13      that was done in this area looked at the  
14      impediments that are caused by not allowing, in  
15      effect, because of market restrictions under sub  
16      megawatt and sub 10 megawatt to come into the  
17      ancillary services market.

18           Those are terrific market impediments.  
19      It would be nice if some study were to address  
20      that. Thank you very much. I look for your  
21      comments on the first question.

22           MR. PRICE: Yeah. Let me just start  
23      with the black start analysis piece, and I think  
24      the assumption, definitely for New York and I  
25      think in the studies here, as well, on black start

1 is that most interconnection rules -- and if  
2 there's an engineer in the room that knows  
3 differently -- when the utility is out and there's  
4 no power to the line, the generators that are  
5 connected to, then that generator can't connect  
6 in.

7 So, in other words, they're not  
8 connected to the distribution system so that with  
9 that type of interconnection scheme there's no  
10 black start possible really.

11 Now, the technical question, --

12 MR. RAWSON: Steve, could you use the  
13 mike?

14 MR. GREENBERG: Sure. This is Steven  
15 Greenberg, again, DE Strategies. The utility grid  
16 goes down, loss of power. The DG unit, the  
17 building will --

18 MR. PRICE: -- scenario, right.

19 MR. GREENBERG: They isolate from the  
20 grid and keep running, where the DG unit shuts  
21 down. And then starts back up after they've  
22 isolated from the grid.

23 But for the customer there's --

24 MR. PRICE: Oh, yeah, --

25 MR. GREENBERG: -- black start.

1           MR. PRICE:  -- no, no, that's true.  The  
2           customer would be fine with their own DG and sort  
3           of their own island.

4           MR. GREENBERG:  But DG is never, in the  
5           scenarios we've talked about, it's not designed to  
6           repower the grid.  However, it reduces the loading  
7           on the grid so that when you have to build the  
8           grid back, if there's limited generation  
9           resources, there's now less demand out there.  So  
10          it acts as sort of --

11          MR. PRICE:  Um-hum.

12          MR. GREENBERG:  -- on the effects of a  
13          blackout.

14          MR. PRICE:  Yeah.  So I guess the point  
15          was that -- and I guess I was thinking about black  
16          start as being, you know, DG injecting energy into  
17          the grid that's down.  And as far as the  
18          interconnection rules now, I don't think that can  
19          happen.

20          MR. EVANS:  The only one thing I wanted  
21          to add to that is, again, I drew a distinction  
22          between network benefits and customer benefits,  
23          and I think I agree that DG, at least in the  
24          current environment, its black start capability or  
25          its ability to run when the grid's down is mainly

1 a customer benefit.

2 And then for it to reconnect is  
3 probably, at best, a problem, and, you know, I  
4 think something that -- well, you're shaking your  
5 head no, and I'm sure that's something we're  
6 working through. But I guess I expressly did not  
7 consider black start as being a network benefit.

8 And then you mentioned ancillary  
9 services, and I think I would characterize the  
10 ability of distributed generators to provide  
11 reactive capability into the system as being an  
12 ancillary service. That's not priced, probably,  
13 as well as it could be. But I don't see any  
14 reason why, if you had the telemetry and the  
15 metering and the wherewithal to manage reactive  
16 power for small generators why you couldn't also  
17 use it as a source of spin. It's just the  
18 overhead.

19 DR. ELY: I think your point is a very  
20 good one. And the other thing, the  
21 interconnection rules are, of course, as you  
22 describe them. And islanding is always thought of  
23 as the complete bugaboo of system restart.

24 I'd like to suggest as a thought piece  
25 that islanding should be thought of as an element

1 of system design. And that, in fact, we build  
2 into campuses an isolated DG capability, that of  
3 islanding and islanding reconnection, as a mode of  
4 operation of distributed generation.

5 That way we could capture much of the  
6 savings in distribution costs that would be  
7 alleviated.

8 MR. RAWSON: Other questions? Let's try  
9 one back here.

10 MR. LITTENEKER: My name is Randy  
11 Litteneker. I'm with PG&E. I just have a quick  
12 compliment and a comment.

13 The compliment is to the two Commissions  
14 on doing this proceeding. It is exactly what we  
15 need to do. There are a variety of policies and  
16 perspectives and incentives, and this is an  
17 excellent opportunity to coordinate them and  
18 evaluate them.

19 The comment is about the distribution  
20 deferral concept and the distribution planning and  
21 the transparent distribution planning issue that's  
22 been the subject of much discussion this  
23 afternoon.

24 In the original distributed generation  
25 rulemaking that the CPUC had some years ago a

1       number of those were topics that were discussed at  
2       some length. And among the people that came on as  
3       witnesses in that proceeding were some of PG&E's  
4       distribution planners who talked about exactly  
5       some of these concepts. They put on some  
6       testimony about how they do distribution planning;  
7       some about how they factor DG into that expansion.

8               And the question that is claimed  
9       sometimes that if you simply install a DG unit on  
10      a constrained circuit, that that will avoid the  
11      need for distribution upgrade. And they  
12      explained, and the Commission agreed, that that  
13      can occur. There are places where DG can avoid or  
14      defer distribution, but it doesn't occur in all  
15      circumstances.

16             Among the questions that's come up, both  
17      from the Commissioner's question and from a number  
18      of other questions is, is there more information  
19      the utilities can provide; is there a better way  
20      of doing that. There are opportunities for  
21      savings that aren't now being realized.

22             And I'd just like to say not only are we  
23      happy to continue to make use of some of that  
24      information we've provided, we are happy to  
25      continue to work with DG advocates and these two

1 Commissions to see what those opportunities are.  
2 If there are opportunities for greater savings,  
3 then we should realize those. If there are  
4 efficiencies to be achieved, that's what we all  
5 should be doing.

6 One of the proposals along the way in  
7 the first proceeding was that the entire  
8 distribution planning process should be completely  
9 transparent, and everything should be available.  
10 All three utilities responded about like you'd  
11 expect.

12 (Laughter.)

13 MR. LITTENEKER: But I suspect there are  
14 some opportunities for improvement, and that's  
15 what I'm happy to confirm, that like the other  
16 utilities, I think there are ways we can work with  
17 people to achieve some improvements and see what  
18 we can do better.

19 So, I thank you for that. Thank you.

20 PRESIDING MEMBER GEESMAN: Well, I thank  
21 you for your comments. I think that's quite  
22 constructive. And let me say a couple things.

23 One, as we go forward I would greatly  
24 appreciate it if you would bring to our attention  
25 matters that you think have previously been

1 addressed and refer us to parts of the earlier  
2 record that might help us avoid going through some  
3 of these pointless circles twice or three times.

4 Two, I don't, for a minute, rule out the  
5 prospect that this is an area that the state can  
6 really screw up. So I think that we need to  
7 proceed with our eyes wide open. And that's why I  
8 do think that your cooperation and helpfulness, as  
9 well as that of the other utilities, is so vital  
10 to avoiding that problem.

11 I think we have a proclivity to want to  
12 act and some frustration with how long it seems to  
13 get regulatory institutions to act. But I do  
14 think that the more information that we can bring  
15 into this kind of forum, and the more input we can  
16 get from the full diversity of views represented  
17 by the different stakeholders, the more likely it  
18 is that we won't do anything stupid. And I place  
19 a value on that.

20 (Laughter.)

21 MR. LITTENEKER: I do, too.

22 PRESIDING MEMBER GEESMAN: I appreciate  
23 your comments very much.

24 MR. LITTENEKER: Thank you.

25 MR. RAWSON: We have time for a couple

1 more questions.

2 MR. WAYNE: My name is Gary Wayne and I  
3 represent PowerLight Corporation. And the  
4 question is to Peter. To what extent is the data  
5 that you used in your Silicon utilities study  
6 available from the major utilities?

7 MR. EVANS: Well, there's two ways to  
8 answer that question. First of all, for example,  
9 the type of information we got from SVP is not,  
10 you know, -- part of the reason that we did this  
11 project the way we did was because SVP was willing  
12 to make this data available to us. But we don't  
13 have liberty to reproduce it.

14 And I think that's generally true with  
15 utilities. That, you know, what we're doing is  
16 simulating a planning tool that would probably  
17 take place -- would be used within the utility  
18 rather than in some sort of a public type of  
19 process, subject to what we just talked about.

20 But you might have been asking whether there  
21 was something unique about that information. And  
22 I think we probably convinced ourselves that  
23 creating a model like the model we created for SVP  
24 could be created relatively easily with any  
25 utility.

1           We found ways to use, in the case of  
2       SVP, all the data was in hard copy form, was  
3       engineering files. We had to create the  
4       electronic files by hand. And it was, I thought  
5       going in it would be an enormous amount of work,  
6       and this was sort of the worst case situation to  
7       try to build a detailed database like this.

8           And it ended up not being that bad. And  
9       I would do it again in a heartbeat. One of the  
10      things that I think we concluded for ourselves was  
11      that even if you're not sure that this type of  
12      detailed analysis would yield really beneficial  
13      results, it's easy enough to do, that it's  
14      probably worth for a utility to just do it.

15           And then once it's done you have the  
16      detailed models and you can analyze a lot of  
17      different things besides the things that we  
18      analyzed. And it's not that difficult when you  
19      know what you're doing. It's not that difficult  
20      to gather this together.

21           But this type of detailed information  
22      about a utility system typically isn't available  
23      on the internet. And usually the utilities are  
24      somewhat reluctant to give it up, because it has  
25      specific customer information in it.

1                   MR. RAWSON: We had a question over  
2 here.

3                   MR. PATRICK: I'd like to talk about  
4 win/win/win/win/win/win.

5                   (Laughter.)

6                   MR. PATRICK: After today's workshop I  
7 can see that DG's a big and complicated issue.  
8 And I'm pleased that the Commission and the PUC  
9 are holding these workshops. I'd like to support  
10 them going forward.

11                   But for a moment I'd like to talk about  
12 something much smaller, and in your mind maybe  
13 correct an unexpected but real and concrete  
14 benefit that could be improved, associated with  
15 DG.

16                   I'd like to connect in your mind DG  
17 with, of all things, cows, milk, cheese, ice cream  
18 and air quality.

19                   Milk is one of the largest commodities  
20 in California and in the San Joaquin Valley. What  
21 you may not know is that thousands of farmers and  
22 dairies now have to comply with federal and new  
23 state air quality requirements to control, in  
24 addition to the PM10 and the NOx that was already  
25 mentioned, but also VOCs and ammonia.

1 I'd like to ask that you track VOCs and  
2 ammonia in addition to the other environmental  
3 gases that you're looking at.

4 For example, in the San Joaquin Valley,  
5 new, modified or expanding dairies will have to  
6 implement best available control technology or  
7 BACT. Again, in the San Joaquin Valley, the only  
8 proposed acceptable BACT technology is an  
9 anaerobic digester with an internal combustion  
10 engine or equivalent, but stops short of  
11 specifying DG.

12 It's fully expected that DG's going to  
13 be provided and present because it provides  
14 support of economics that enable the dairies to  
15 provide emission control technology in thousands  
16 of dairy sites throughout California. Taps  
17 renewable energy source, and solves a waste  
18 problem.

19 So what I'd ask for, both of the  
20 Commissioners and the people that are on the PUC  
21 and Energy Commission Staffs, is that they  
22 continue to look out for small DG generators, help  
23 California remain the leader in milk, cheese,  
24 butter, ice cream, air quality and DG.

25 We'd like to follow up with a written

1 statement later. Thank you.

2 MR. RAWSON: Was there a question for  
3 the panel or did you want them to comment to you  
4 about VOCs and ammonia?

5 MR. PATRICK: I'd be interested, thank  
6 you.

7 PRESIDING MEMBER GEESMAN: And we look  
8 forward to his written comments.

9 MR. RAWSON: Okay.

10 PRESIDING MEMBER GEESMAN: And we do  
11 intend you to continue to stand up for the small  
12 DG.

13 MR. RAWSON: I think we have time for  
14 one more question; I'll give Tracy a chance.

15 PRESIDING MEMBER GEESMAN: Go ahead.

16 MS. SAVILLE: Pardon my cold; my voice  
17 will be very shaky. I'm Tracy Saville. I'm with  
18 a company called TK & Company. We're a strategic  
19 issues consulting firm. And I think I know just  
20 about everybody here in the room, so it's almost  
21 like being at a family reunion.

22 That being said, this room has  
23 undoubtedly the most significant body of knowledge  
24 on the subject of unregulated energy markets in  
25 DER than probably anyplace in the world. For me

1       that means what we know collectively and commonly  
2       understand will certainly make this proceeding  
3       valuable.

4               But I'm very concerned about what we  
5       don't know, and what the cost of this lack of  
6       understanding actually means to the quality of the  
7       outcomes of this proceeding, and to serving the  
8       best interests of Californians.

9               My comment goes to this issue and I'll  
10       expand on it in my written comments, from a global  
11       perspective of resource investment and resource  
12       adequacy, and what we all ought to be collectively  
13       obligated and responsible for insuring.

14              Unless we have a level of transparency  
15       and access to grid data, and analyze this data  
16       through existing optimization technology, such as  
17       that available by a paradigm software source like  
18       optimal technology. Their AEMPFAST and SUREFAST  
19       products, for example -- which I, for the record,  
20       don't represent -- that offers a depth of  
21       granularity necessary to understand where and when  
22       any resource should be placed irrespective of any  
23       single system player's self interest.

24              Wherever we end up in our dialogue and  
25       discussion around choosing quantitative decisions

1       for values of components, cost and benefits,  
2       whatever methodology we choose is most appropriate  
3       for looking at DER, however we decide we're going  
4       to allocate those costs and benefits, and in what  
5       mechanisms, under what tariffs, under what rate  
6       structures, unless we take a look at an optimized  
7       analysis of the grid in totality, we'll always be  
8       under-optimized, which will always and inherently  
9       be more costly, less efficient and less reliable.

10               I think we have a unique opportunity,  
11       and we clearly have the technology available today  
12       that we didn't even have three years ago, to  
13       understand what our grid system looks like. I  
14       believe this understanding is critical and should  
15       be mandated. And I believe also would go to  
16       solving Joe Iannucci's remarks regarding the  
17       controversial-ness and lack or quality of data  
18       granularity.

19               In my opinion, we shouldn't be satisfied  
20       as a matter of policy to accept only a load  
21       serving utility's determination of need with  
22       regard to our distribution system. With all due  
23       respect to my utility colleagues, because they  
24       admittedly have an inherent priority obligation to  
25       make distribution and resource planning decisions

1 and investments that first serve the interests of  
2 their shareholders, which is equal to insuring  
3 their lowest risk and highest rate of return on  
4 their investments.

5 If we implement AB-57 and the Energy  
6 Commission's IEPR and joint energy action plan,  
7 using loading order directives and least cost  
8 competitive bidding resource investment  
9 requirements, then it follows we are obligated to  
10 conduct and optimize analysis of the grid, under  
11 open and unbiased conditions.

12 This will require specific new  
13 regulation to require a level of cooperation,  
14 access to, and disclosure of, distribution data  
15 that we don't have today, but we would implicitly  
16 need.

17 This level of optimized analysis will do  
18 more than just illuminate DER, but every resource  
19 investment made or contemplated. And I think  
20 anything less would be irresponsible to ratepayers  
21 and to ourselves in this process.

22 Thank you.

23 PRESIDING MEMBER GEESMAN: Tracy, I'm  
24 glad we gave you the last word because I think  
25 that's a good point on which to close this

1 workshop. It's the first. There will be more to  
2 come. I do want to have access or make reference  
3 to the earlier record developed at the PUC, and  
4 make certain that we don't trod over too much  
5 ground that so many of you have been over before.

6 And I certainly thank all of you for  
7 your attendance today, and participation, and hope  
8 that you continue to stay involved in this as we  
9 move it forward.

10 We'll be adjourned.

11 (Whereupon, at 5:34 p.m., the workshop  
12 was adjourned.)

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